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Composition and depositional environment of major eastern Canadian oil shales

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ABSTRACT

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In Eastern Canada, following the Acadian Orogeny, two lithologically and chronologically distinct sequences of oil shale were deposited in the Late Devonian/Carboniferous Maritimes Basin.

The oldest sequence occurs within the Moncton Subbasin, a transcurrent and asymmetric basin 200 km in length in southeastern New Brunswick. The oil shales are largely confined to the medial part of the 165–1800 m thick Early Carboniferous (Tournaisian) Albert Formation. The oil shales range from massive slightly organic-rich dolostone to carbonate-rich lamosite with an organic fraction of 1–30% TOC and comprising mainly alginite with locally abundant liptodetrinite and vitrinite. Rock-Eval and chromatography data indicate mostly Type I and Type II kerogens. Lamalginite fluorescent spectra indicate immature to mature sediments, in agreement with surface oil shows and the presence of a small oil and gas field sourced from Albert oil shales. The oil shale composition reflects deposition in a chemically stratified lacustrine setting characterized by slightly saline and alkaline waters and deltaic sedimentation.

The younger sequence occurs within the Stellarton Basin, a 6×18 km pull-apart basin situated in northern Nova Scotia. The oil shales form part of the 2600 m thick Late Westphalian B–Early Westphalian D coal-bearing Stellarton Formation; a total of 60 oil shale beds (1–45 m thick), some transitional to coal, have been documented. The oil shale lithotypes are silicate-rich and include fissile shale, minor blocky (cannel) shale and lesser stellarite (boghead shale) with an organic fraction, depending upon lithotype, of 1–41% TOC comprising variable amounts of liptinitic groundmass material, telalginite and vitrinite. Rock-Eval, petrography and gas chromatography, data indicate mature Type II and locally Type I and Type III kerogens. Extract, chromatography and carbon isotope data

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indicate that the coals of the formation, rather than the oil shales, are the most probable source of the hydrocarbon shows within the Stellarton Formation. The composition of the oil shales and the transition of some oil shales to coal reflects deposition in a nearshore to open lacustrine environment bordered by peat swamps.

The principal causes for compositional differences between the Albert and Stellarton oil shales are: (1) the influence of basin size and paleogeographic setting on sediment supply to the Albert and Stellarton lakes; (2) the hydrological conditions (closed versus open) of the Albert and Stellarton lakes; (3) the influence of swamps on the pH and organic content of the Stellarton lakes; and (4) climate.

INTRODUCTION

Oil shale is a general term applied to all fine-grained sedimentary rocks that yield liquid hydrocarbons in excess of 25 litres per tonne of rock when heated to about 500°C (Yen and Chilingarian, 1976; Cook et al., 1981; Tissot and Welte, 1984). Lithologically, these rocks may be shale, marl or carbonate (Tissot and Welte, 1984), or transitional to coal and carbonaceous shale (Cook et al., 1981). Liquid hydrocarbons derived from these rocks are produced through the thermal alteration of inherent organic matter. The bulk of the organic matter in oil shale is typically contributed by material of algal origin (liptinite macerals) with only minor contributions from material of (terrestrial) plant origin (humics: vitrinite, inertinite macerals; Hutton et al., 1980). The algal material may be present as poorly preserved detritus or as discrete laminae or masses.

Eastern Canada contains two significant oil shale deposits; the Albert Formation oil shales of New Brunswick and the Stellarton Formation oil shales of Nova Scotia. Interest in the exploration and development of these deposits has traditionally reflected oil pricing trends. However, these two deposits have attracted continued interest as a potential source of hydrocarbons since their discovery. The Nova Scotia oil shales have been mined on a limited scale during two periods, 1852–1859 and 1929–1930 (Ells, 1910; Swinnerton, 1930; Douglas and Campbell, 1942) and the New Brunswick oil shales are attracting attention for the potential offered in reducing sulphur emissions during co-combustion with high sulphur coal for thermal power generation (Macauley et al., 1985).

The aim of this paper is to compare these two oil shale deposits in terms of composition and depositional environment. Thus, this paper summarizes the lithology, organic petrography and geochemistry of the two oil shale deposits and discusses possible factors controlling compositional differences.

GENERAL GEOLOGY

Oil shales of the Albert and Stellarton Formations of Eastern Canada occur within the Upper Paleozoic basin-fill of the Maritimes Basin (Fig. 1). With

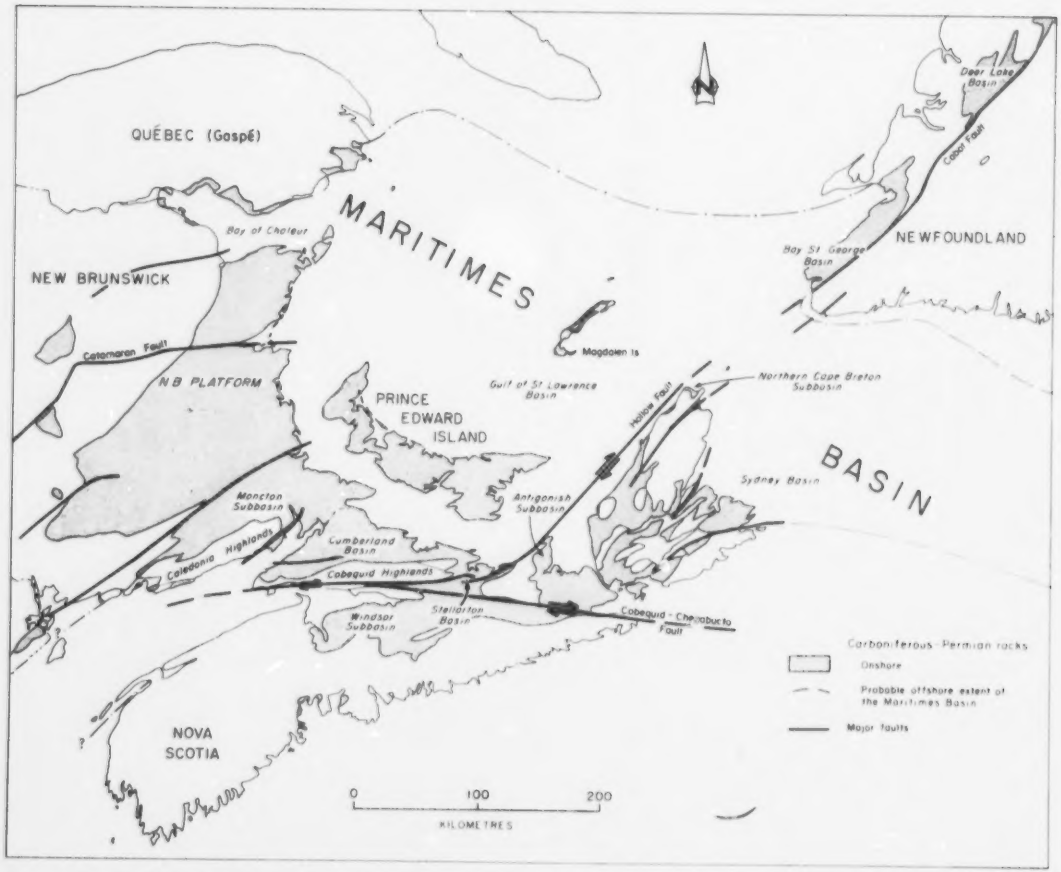

Fig. 1. The Maritimes Basin of Atlantic Canada showing the location of the Moncton Subbasin, the Stellarton Basin and other component basins of the Maritimes Basin.

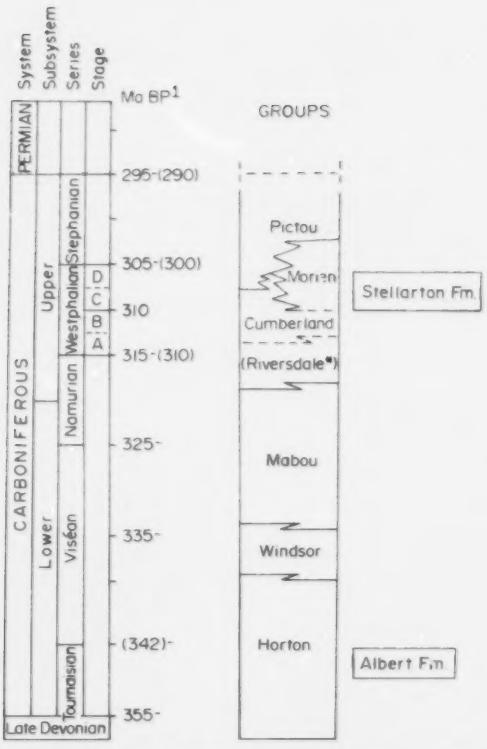

Fig. 2. Stratigraphic column of the Late Paleozoic basin-fill of the Maritimes Basin. Modified from Calder (1991).

the exception of the predominantly marine Windsor Group (Fig. 2), the basin-fill is entirely of continental origin. The Horton Group which includes the Albert Formation (Fig. 2), represents the earliest record of sedimentation (Late Devonian to Tournaisian) in the basin following the Acadian Orogeny (Hacquebard, 1972). The Horton Group averages about 3000 m thick (1000–5000 m) and comprises a lower red coarse-grained alluvial sequence, a middle mainly grey lacustrine sequence and an upper red coarse- to fine-grained alluvial sequence (Gussow, 1953; Murray, 1960; Boehner et al., 1986; Martel, 1990). Deposition of Horton strata was followed by incursion of the proto-Atlantic ocean and subsequent deposition of the Windsor Group.

The Stellarton Formation (Fig. 2) is the thickest (2600 m) sequence of

late Westphalian B to mid-Westphalian D strata within the Maritimes Basin. The lithology of the formation is in some respects similar to age-equivalent strata of the Morien Group, the Cumberland Group (Fig. 2) and an unnamed coal-bearing sequence that underlies much of the Gulf of St. Lawrence (Hacquebard, 1986). Collectively, these units contain the most widespread coal measures within the Maritimes Basin (Hacquebard, 1986).

The Maritimes Basin comprises a number of "subbasins" and "basins" a few tens to thousands of square kilometres in area. The terms "subbasin" and "basin" have been informally assigned to areas within the Maritimes Basin without a rigorous regard to hierarchy. The boundaries of the subbasins and basins are largely recognized on the basis of structural discontinuities, unconformities, or the erosional limits of basin fill. The Albert Formation was deposited in the Moncton Subbasin, a transcurrent and fault-controlled asymmetric basin (Webb, 1969; Bradley, 1982), 3750 km^2 in area, located in southern New Brunswick (Fig. 1). Oil shale-bearing strata that are equivalent in age to the Albert Formation occur within the Antigonish Basin, the Windsor Subbasin and the Northern Cape Breton Subbasin (Fig. 1) (Smith and Naylor, 1990). The Stellarton Formation was deposited in the Stellarton Basin, a small (120 km^2) pull-apart basin, located between the Hollow and Cobequid Faults of central northern Nova Scotia (Fig. 1). Dextral strike-slip movements along these faults during Westphalian B-C time are believed to have been responsible for formation of the Stellarton Basin (Yeo and Ruixiang, 1986, 1987). Thin oil shale beds, equivalent in age to those of the Stellarton Basin, occur in the two largest component basins of the Maritimes Basin, the Sydney and Gulf of St. Lawrence Basins (Smith and Naylor, 1990) (Fig. 1).

ALBERT FORMATION OIL SHALES

Stratigraphy

Within the Moncton Subbasin (Fig. 3), the Horton Group is approximately 3500 m thick and comprises three conformable formations: the basal red beds of the Memramcook Formation, the medial grey conglomerates, sandstones, shales and oil shales of the Albert Formation and the upper red beds of the Weldon Formation (Fig. 4a).

The Albert Formation is mainly exposed around the periphery of the subbasin (Fig. 3). Surface exposures and regional boreholes indicate the formation varies considerably in thickness. For example, in the southwest part of the subbasin the formation is about 165–500 m thick, whereas in the northwest it is about 800 m thick. In the northeast an incomplete (faulted) Albert section is up to 1500 m thick and in the southeast, depending on location, the formation ranges from 1000–1800 m in thickness.

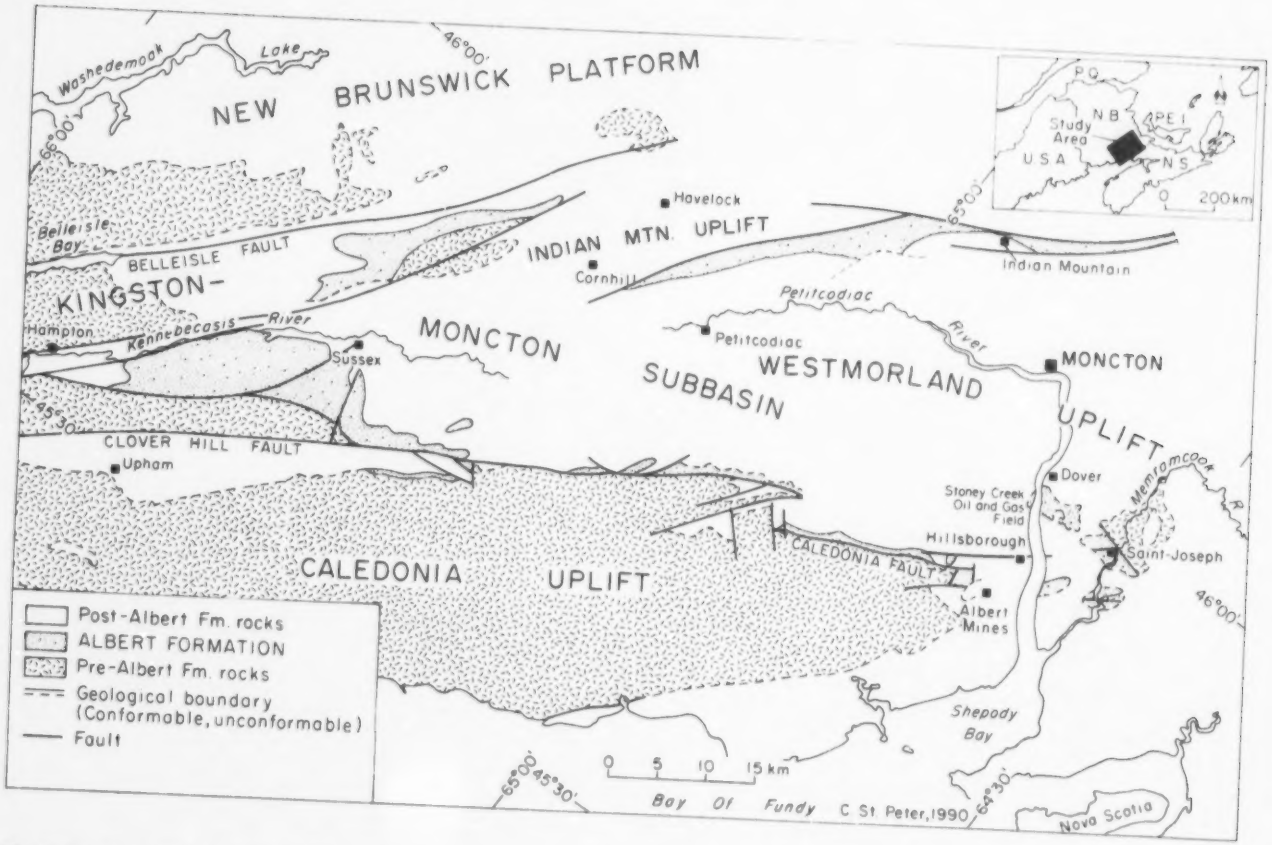

Fig. 3. Geology of the Moncton Subbasin, New Brunswick.

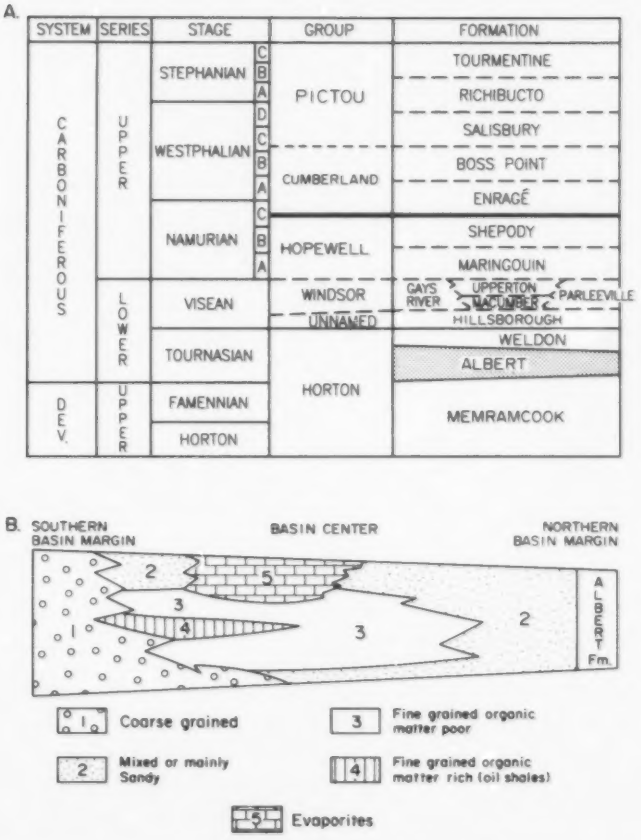

Fig. 4. (A) Generalized stratigraphy of the Moncton Subbasin, New Brunswick. (B) Detailed lithofacies subdivision of the Albert Formation; orientation implies a south to north section from Caledonia uplift to Stoney Creek Oil and Gas field (see Fig. 3).

Oil shale comprises a significant lithofacies only in the southeastern part of the subbasin. In this area, thickness of individual oil shale beds (see below and Fig. 6) range from 0.3 to 4.8 m (Macauley and Ball, 1982; Smith, 1985). Composite oil shale intervals comprising interbedded oil shale lithotypes range from 10 to 20 m in thickness and contain an average shale oil yield of greater than 90 l/t of rock (St. Peter, 1988).

In the southeast part of the subbasin, the Albert Formation has been divided into three members which are named, from oldest to youngest: Dawson Settlement, Frederick Brook and Hiram Brook (Greiner, 1962). The Dawson Settlement Member comprises sandstone, siltstone, shale, minor bituminous (oil) shale, limestone and conglomerate. The Frederick Brook Member con-

sists of oil shale, calcareous shale, siltstone and limestone. The Hiram Brook Member includes siltstone, shale, sandstone and minor oil shale. The three-fold division of Greiner (1962) has been retained by some workers (e.g. Macauley and Ball, 1982; Kalkreuth and Macauley, 1984; Macauley et al., 1985) and the Frederick Brook Member further subdivided into zones. However, basin-wide studies indicate that the three-fold classical "layer cake" subdivision of the formation cannot be recognized outside the southeast part of the subbasin because of rapid facies changes (St. Peter, 1989a,b).

Subdivision of the Albert strata on the basis of lithologic facies has been recently made by C. St. Peter with five lithologic facies recognized (Fig. 4b): (1) a coarse-grained facies, (2) a mixed or mainly sandy facies, (3) a fine-grained, organic-poor facies, (4) a fine-grained, organic-rich facies (oil shales) and (5) an evaporite facies. The fine-grained, organic-rich facies, which includes most of the oil shales, occurs as "tongues" at several positions within the Albert Formation and comprises: (i) interbedded brown, laminated to microlaminated, dolomitic and calcareous, kerogenous shale (oil shale), (ii) brown, dolomitic and calcareous, kerogenous mudstone, (iii) grey mudstone, (iv) grey to brown, fine- to medium-grained, micaceous and feldspathic sandstone, and (v) minor limestone, dolostone and conglomerate.

Oil shale lithology

Subdivision of the Albert oil shales into lithotypes was first undertaken by King (1963). King (1963) recognized four types (on the basis of organic/inorganic lamination character and the content of organic matter relative to silicates and carbonates): (1) blocky laminated marlstone, (2) papery marlstone, (3) low-grade sandy marlstone and (4) massive dolomitic marlstone. King's (1963) basis for lithotype subdivision, with minor variations, was used by Smith (1985) and Smith and Gibling (1987) who also recognized four oil shale lithotypes. They referred to them as oil shale A, oil shale B, oil shale C and massive oil shale (Table 1, Fig. 5a–d). Oil shales A, B and C are laminated while massive oil shale is rather nondescript, with the exception of rare diffuse and truncated laminae. Oil shale A and B also contain highly crenulated and contorted laminae and loop bedding, features also recognized by King (1963) and utilized in distinguishing his blocky laminated marlstone. Fish fragments are common to all of the oil shale lithotypes and ostracods are present locally (Greiner, 1962). Oil shales A and B tend to contain whole palaeoniscoid fish skeletons in addition to fish fragments (Lambe, 1909; Greiner, 1962).

It is apparent from Table 1 that, on the basis of lamination thickness and organic laminae continuity, oil shale A grades into oil shale B which in turn grades into oil shale C. Drill core sections depicted in Fig. 6 illustrate typical sequences of oil shale and show the gradational nature of transitions from one

TABLE I

Albert Formation oil shale lithotypes (after Smith and Gibling, 1987)

Lithotype	Appearance	Composition	Grain size	Colour	Other features
Oil shale A	Couplets of organic and inorganic laminae; 0.23–0.59 mm (0.32 mm, average) thick; organic laminae	dolomitic/calcareous (locally micaceous)	clay	Dark yellowish brown	Fish fragments, loop bedding, pyrite framboids, microfaults
Oil shale B	Couplets of organic and inorganic laminae; 0.33–0.69 mm (0.49 mm average) thick; organic laminae continuous	dolomitic/calcareous (locally micaceous)	clay	Pale/dark yellowish brown	Fish fragments, loop bedding, pyrite framboids, microfaults
Oil shale C	Couplets of organic and inorganic laminae; 0.59–0.89 mm (0.73 mm average) thick; organic laminae discontinuous	dolomitic (locally calcareous to noncalcareous)	clay	Light olive grey to pale yellowish brown	Fish fragments, pyrite framboids, siderite nodules, calcite veinlets, microfaults
Massive oil shale	Massive, organic matter finely dispersed throughout	dolomitic/calcareous (locally micaceous)	clay-silt	Dark yellowish brown	Fish fragments, pyrite framboids

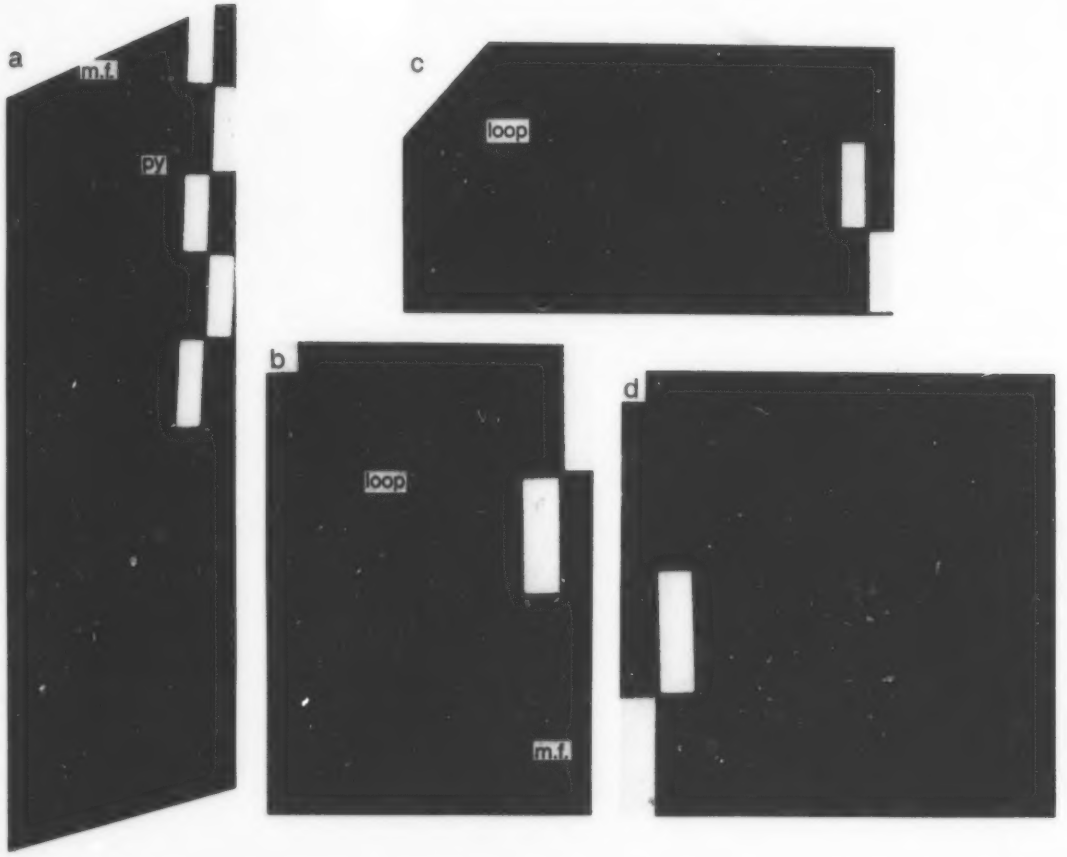

Fig. 5. Oil shale lithotypes, Albert Formation, Moncton Subbasin, New Brunswick. (a) Oil shale C showing microfaults (*m.f.*) and pyrite framboids (*py*), (b) Oil shale B showing microfaults and loop-bedding (*loop*), (c) Oil shale A showing loop-bedding and (d) Massive oil shale displaying poorly developed and disrupted lamination and microfaults.

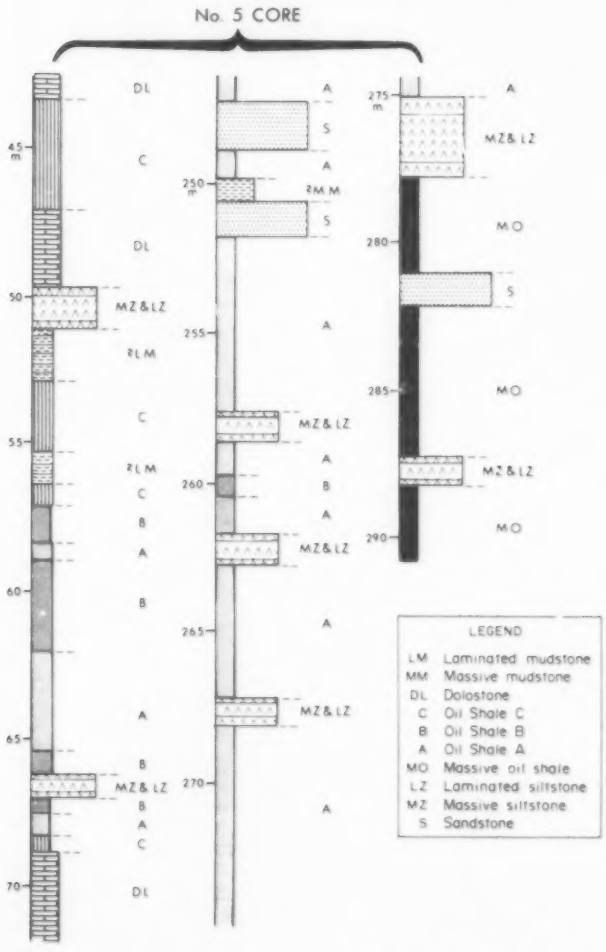

Fig. 6. Selected vertical sequences of Albert Formation lithotypes from the Canadian Occidental Albert Mines No. 5 drillhole to illustrate the observed gradation between oil shale types.

oil shale type to another. In particular, laminated mudstone grades through oil shale C into progressively richer oil shales B and A (Fig. 6) with individual oil shale beds separated by beds of siltstone and sandstone. Massive oil shale is generally associated with coarser clastic sediments such as siltstone and sandstone. Individual massive oil shale beds are typically separated by these coarse clastic sediments (Fig. 6). Oil shale C grades through a decrease in organic content and by an increase in dolomite or calcite into dolostone or limestone.

Oil shale composition

The only study to date which relates the composition of the Albert oil shales to lithotype is that by Smith (1985) and Smith and Gibling (1987). Accordingly, the numerous historical observations on mineralogy, chemistry and organic matter are not readily assignable to one or another of oil shale lithotypes A, B, C or massive. Most previous data are published, for example, as the major element chemistry, mineralogy, or total organic carbon (TOC) content of oil shale (undivided). Some of the compositional data summarized below is therefore unavoidably general.

Inorganic composition

The average percentages of major minerals for the four oil shale lithotypes are given in Table 2. The minerals were identified and their proportions determined by semi-quantitative X-ray diffraction (XRD) and, accordingly, the numbers should be interpreted with caution. The XRD data imply that the inorganic fraction of all the oil shale lithotypes comprises mainly illite, carbonates, quartz and feldspar with minor amounts of other silicates (for example, analcite) and pyrite.

Illite is by far the most significant clay mineral in all four lithotypes. The data appear to indicate a decrease in illite content from the microlaminated oil shale A to the more thickly laminated oil shale C. Smectite, kaolinite and chlorite are present in only minor amounts.

Carbonate minerals comprise about one-third of the inorganic component of the oil shales; calcite and dolomite are the only significant carbonates. The calcite content is highest in oil shale A and lowest in oil shale C. The high dolomite content in types B and C led Macauley and Ball (1982) to designate these rocks dolomite marlstones. It is probable that the dolomite is mainly ankeritic. Chowdhury and Noble (1989) determined from scanning electron microscopy (SEM) on twelve shale samples an average ankerite content of 18.3%. Similarly, White et al. (1988) found, using SEM, ankerite to be more

TABLE 2

X-ray diffraction average mineral percentages for the inorganic fraction of oil shales from samples of three Albert Formation drill cores. *QZ*=quartz, *AL*=Albite, *KF*=K-feldspar, *CA*=calcite, *DO*=dolomite, *SI*=siderite, *IL*=illite, *SM*=smectite, *KA*=kaolinite, *CH*=chlorite, *AN*=analcite, and *PY*=pyrite (modified after Smith, 1985)

Lithotype	Samples	QZ	AL	KF	CA	DO	SI	IL	SM	KA	CH	AN	PY
A	11	10.9	17.1	1.0	14.6	7.8	0.6	43.4	0.9	0.7	0.8		1.0
B	5	12.7	11.3	4.7	13.2	18.4	1.9	34.3	0.8	0.5	1.0		1.1
C	10	9.6	12.4	5.0	8.5	15.7	0.6	28.7	2.1	1.6	3.4	11.1	4.1
Massive	2	8.4	8.8	9.5	24.5	6.3	1.4	38.3	0.7	0.7	1.0		1.2

abundant than dolomite in their studies of oil shales from the southeastern part of the subbasin. Siderite and pyrite, common diagenetic minerals formed in reducing environments, are present (the latter as lenses, laminae, nodules and fine disseminations) in all oil shales in minor amounts.

All four lithotypes contain subequal amounts of quartz (8–13%) and albite feldspar (9–17%). Plagioclase is much more abundant than potash feldspar, a finding also reached by White et al. (1988) from their SEM observations.

Analcite only occurs in laminated shales with less than about 7% TOC (cf. tables 10 and 15 in Smith, 1985). This is in agreement with XRD data from Macauley and Ball (1982) where only laminated oil shales with less than 5.5 wt.% organic matter are seen to contain analcite. The mineralogical data supports the contention of Macauley et al. (1985) and Mossman et al. (1987) that analcite is restricted to those shales with the lowest total clay content. They proposed that the analcite originates from the alteration of clays in sodium-rich alkaline solutions. In addition to analcite, evidence of sodium-bearing waters is provided by cubic halite pseudomorphously replaced by calcite in oil shale beds at Albert Mines.

In addition to the common minerals, Macauley and Ball (1982) and White et al. (1988) have identified accessory gypsum, szomolnokite, apatite, tourmaline, rutile, biotite, staurolite, ilmenite, hornblende, epidote, almandine, andradite and chalcopyrite. Of these, apatite is by far the most frequently reported. In the northeast part of the subbasin, fluorite is seen in vugs and fractures within a fault zone and Mossman et al. (1987) report the presence of britholite $(CeCa)_5SiO_4(PO_4)_3(OH,F)$, haradaite $(SrVSi_2O_7)$, anapaite $Ca_2Fe(PO_4)_24H_2O$ and collophane.

The major element chemistry of the inorganic fraction of oil shale lithotypes A, B, C, and massive has been examined by Smith (1985) and is summarized in Table 3 and Fig. 7. The data suggests that there are no radical differences in major oxide chemistry among the oil shale types. The chemistry does however confirm some of the conclusions drawn from the mineralogical determinations (cf. Tables 2 and 3). The Fe and Mg contents show a sympa-

TABLE 3

Major element chemistry in weight per cent of oxides for Albert Formation oil shale lithotypes (A, B, C and massive) from core samples of Petro-Canada Dover Nos. 1 and 2 and Canadian Occidental Albert Mines No. 5 (modified after Smith, 1985)

Lithotype	Samples	SiO_2	Al_2O_3	Fe_2O_3	MgO	CaO	Na_2O	K_2O	MnO	P_2O_5
A	7	38.36	9.12	2.98	2.22	11.99	1.39	1.25	0.05	0.26
B	5	31.99	8.49	4.18	3.78	18.08	1.06	1.17	0.10	0.14
C	10	42.62	12.12	4.09	4.89	10.01	2.79	2.52	0.07	0.09
Massive	1	40.31	9.53	3.53	2.06	14.19	1.47	1.22	0.10	0.16

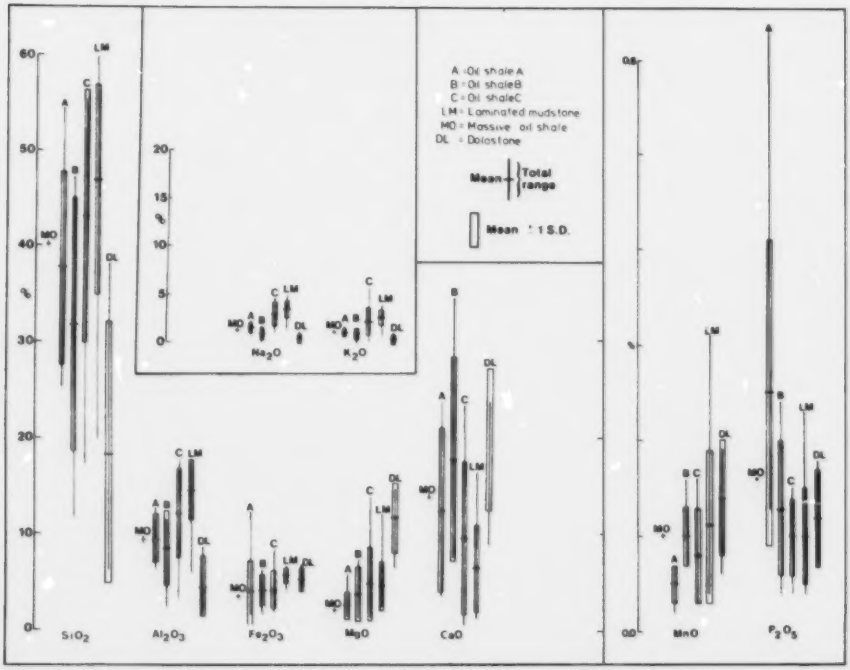

Fig. 7. Major oxide data in relation to oil shale lithotype, Albert Formation. Associated lithotypes are shown for comparison.

thetic relationship and both are highest for the most dolomitic (ankeritic) lithotypes B and C. Calcium content is greater for the more thinly laminated oil shales (lithotypes A and B) than for the more thickly laminated shales (lithotype C) reflecting the greater calcite content in the former. This has been convincingly demonstrated in a recent study by Three-D Geo-Consultants Ltd. (1990) on 686 samples from four drillholes in the Albert Mines area (Fig. 3). The thinly laminated shales there, in the Albert Mines Zone of Macauley and Ball (1982), contain 7.61 wt.% "available calcium" whereas the more thickly laminated shales (lithotype C), in the Dolomite Marlstone Zone of Macauley and Ball (1982), contain only 4.57 wt.% "available calcium".

The Na content in lithotype C is nearly twice that of the other lithotypes. This apparently reflects the high content of analcite in the type C shales. The phosphorus content is highest in lithotype A. It is assumed that this is due to the presence of abundant algal matter and fish skeletons or scales which are more frequently seen in the microlaminated shales.

Smith (1985) has compared the major oxide chemistry of the organic-rich oil shales with associated organic-poor lithotypes and has shown that the Si,

Al, Na, K, Mg and Fe contents of the organic-poor rocks are significantly higher than in lithotype A. This is in agreement with the higher silicate content of the organic-poor facies.

There is no trace element chemistry data available on the four Albert oil shale lithotypes as defined by Smith (1985) and Smith and Gibling (1987). However, Pickerill and Carter (1980) have published trace element data and, from their brief sample descriptions, the fine-grained rocks can be grouped into three types: laminated oil shales, massive oil shales and organic-poor mudrocks. The average trace element composition of these three rock-types is shown in Table 4. Mossman et al. (1987) provided trace element analyses on 68 Albert Formation samples including 14 organic-rich (1.49–17.35 wt.% TOC) mudrocks/oil shales and 22 organic-poor (0.26–1.41 wt.% TOC) mudrocks. The average trace element content of the 36 samples is summarized in Table 5.

An examination of the data for those elements common to both Tables 4 and 5, for example Cu, Pb and Sr, indicates that the absolute values may in part depend upon the method of analysis and/or the laboratory. Regardless, by comparing the trace element contents of organic-rich versus organic-poor

TABLE 4

Trace element chemistry (in ppm) of Albert Formation laminated oil shales, massive oil shales and organic-poor mudrocks (after Pickerill and Carter, 1980). The method(s) of analysis is (are) not given by Pickerill and Carter (1980)

Rock-type	Laminated oil shale	Massive oil shale	Organic-poor mud rocks
No. of samples	6	3	22
Element			
Lithium	91	85	58
Beryllium	6	4	6
Boron	0.33	0.32	0.41
Copper	65	56	60
Lead	47	55	48
Zinc	98	74	72
Molybdenum	20	48	19
Nickel	48	38	40
Chromium	59	54	70
Silver	2	2	1
Gold	N.D.	0.13	N.D.
Vanadium	77	66	92
Rubidium	67	60	46
Strontium	807	841	657
Gallium	N.D.	N.D.	N.D.
Barium	98	87	101
Uranium	7.6	7.0	6.0
Phosphate	2680	600	410
Fluoride	760	1150	407

N.D. = not determined.

TABLE 5

Average trace element chemistry (in ppm) and TOC (in wt.%) of Albert Formation organic-rich mudrocks (includes oil shales) and organic poor mudrocks (after Mossman et al., 1987). The phosphorus content was measured by DCP emission spectroscopy and the concentrations of the other 15 elements were measured by X-ray fluorescence

Rock-type	Organic-rich mudrocks	Organic-poor mudrocks
No. of samples	14	22
TOC	4.48	0.73
Copper	33	31
Lead	17	19
Zinc	76	102
Nickel	35	37
Chromium	62	76
Vanadium	119	115
Rubidium	80	99
Strontium	628	425
Gallium	15	19
Barium	367	634
Yttrium	52	26
Zirconium	125	144
Niobium	11	15
Thorium	38	6
P_2O_5	8230	1780
TiO_2	5690	6710

rocks it is apparent that the organic-rich lacustrine oil shale facies is relatively enriched in phosphorus, fluorine, thorium, strontium, yttrium and perhaps to a lesser degree uranium.

The high content of phosphorus in the organic-rich rocks supports the findings in Table 3. It appears that phosphorus is either fixed by the indigenous organic matter (syngenesis) or is preferentially concentrated by the organic matter during diagenesis (Mossman et al., 1987). Yttrium is known to be commonly associated with algal matter (Vine and Tourtelot, 1970), but it along with fluorine and strontium are also common accessory elements in the apatite group of minerals (Winchell and Winchell, 1964), common accessory minerals in the Albert organic-rich rocks as discussed above. The enrichment in strontium may result from substitution within calcite. The association of uranium and thorium with black shales and particularly with organic matter in shales is well established (Vine and Tourtelot, 1970; Mott and Drever, 1984).

TOC and maceral composition

Smith (1985) has determined the total organic carbon (TOC) content and types of macerals (the latter by fluorescence microscopy) for 20 samples of

A, B, C and massive oil shales obtained from drill cores of the Albert Formation in the southeastern part of the Moncton Subbasin. The results are summarized in Table 6 and Figs. 8 and 9.

The microlaminated oil shale A is the richest oil shale lithotype with an average TOC content of 14.3 wt.% for nine samples (Fig. 8). The organic matter occurs mainly as very thin continuous laminae consisting of lamalginite with subordinate liptodetrinite and minor fusinite and sporinite (Fig. 9a). Laminated oil shale B contains less than one-half the TOC content (average 6.6 wt.%) of oil shale A. The organic matter in type B comprises mainly lamalginite, which occurs as continuous laminae (Fig. 9b). Type B also contains significantly higher amounts (more than twice as much) of liptodetrinite (average 21 vol.%) compared to oil shale A. The most thickly laminated oil shale, type C, contains about 3 wt.% TOC and is characterized by discontinuous organic laminae of subequal quantities of lamalginite and liptodetrinite (Fig. 9c). The massive oil shale lithotype contains about 7 wt.% TOC (Table 6) which is comparable to the mean TOC content of lithotype B. The organic matter in massive oil shale is mainly finely-dispersed liptodetrinite with minor telalginite, sporinite and lamalginite (Tables 1 and 6; Fig. 9d).

There are several hundred published and unpublished TOC determinations on organic-rich Albert rocks throughout the Moncton Subbasin in addition to those values given by Smith (1985) and Smith and Gibling (1987). Recent TOC data include those reported by Macauley and Ball (1982) (95 drillcore samples), Brown and Whaley (1986) (505 drillcore samples) and St. Peter (1990, unpublished data) (66 outcrop and 58 drillcore samples). Collectively, these data show TOC contents ranging from 0.17–29.31 wt.%. The highest values are from beds in the southeastern part of the Moncton Subbasin. This corroborates outcrop observations which indicate that oil shale beds are more abundant and organic-rich in the southeastern areas of the subbasin.

In addition to the maceral studies of Smith (1985) and Smith and Gibling

TABLE 6

Average TOC (wt.%) and percentages of macerals in oil shale lithotypes A, B, C and massive from samples obtained from drillcore sections at Dover and Albert Mines (modified after Smith, 1985)

Rock-type	A	B	C	Massive
No. of samples	9	7	3	1
T.O.C.	14.33	6.37	2.92	7.26
Lamalginite	85.6	71.8	51.4	2.0
Sporinite	1.6	3.2	3.5	6.3
Liptodetrinite	9.3	21.0	42.9	82.0
Telalginite	0.6	1.2	0.4	5.6
Fusinite	2.2	2.4	1.0	3.3
Vitrinite	0.5	0.4	0.8	0.6

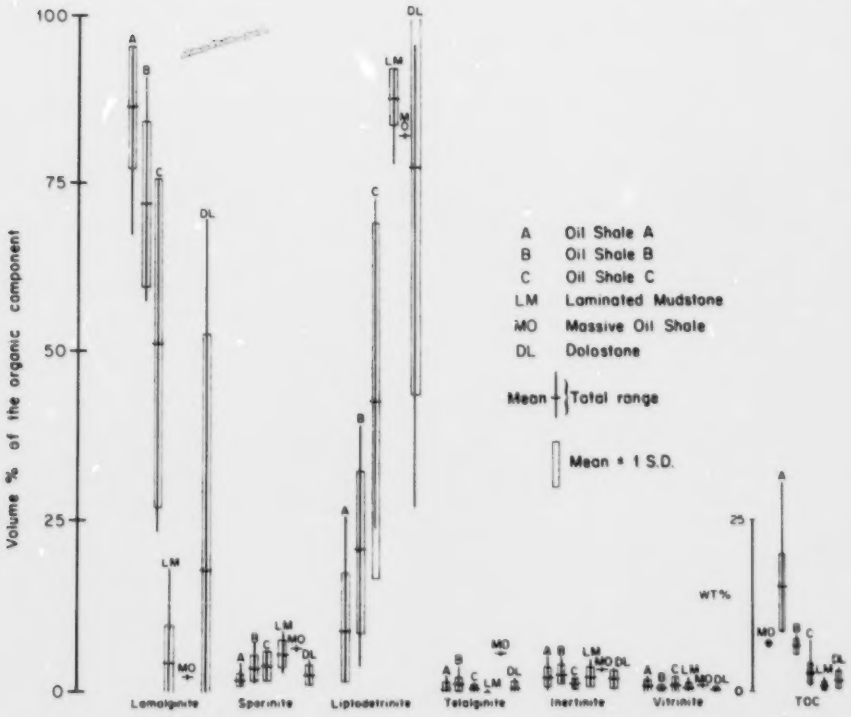

Fig. 8. Total organic carbon (TOC) content and organic petrology data in relation to oil shale lithotype, Albert Formation. Associated lithotypes are shown for comparison.

(1987), maceral data on ten drillcore samples has been reported by Kalkreuth and Macauley (1984). Also, van Helden (1983, unpublished data), of Chevron Canada Resources Limited, carried out a regional study (35 surface grab samples) of maceral composition and thermal alteration indices across the subbasin. Taken together, the data of Kalkreuth and Macauley (1984) and van Helden (1983, unpublished data) suggest that the organic matter in the oil shale strata from the south part of the subbasin is dominantly algal; a finding supported by Smith (1985) and Smith and Gibling (1987). The shales in the southwestern part of the subbasin, being lower in TOC, contain less lamalginite and correspondingly more liptodetrinite, vitrinite and inertinite. The strata in the northeastern part of the subbasin, although organic-poor, contain predominantly algal organic matter.

Rock-Eval pyrolysis

The regional distribution of maceral types, as assessed from microscopic analysis, is corroborated by a fairly extensive organic geochemical database.

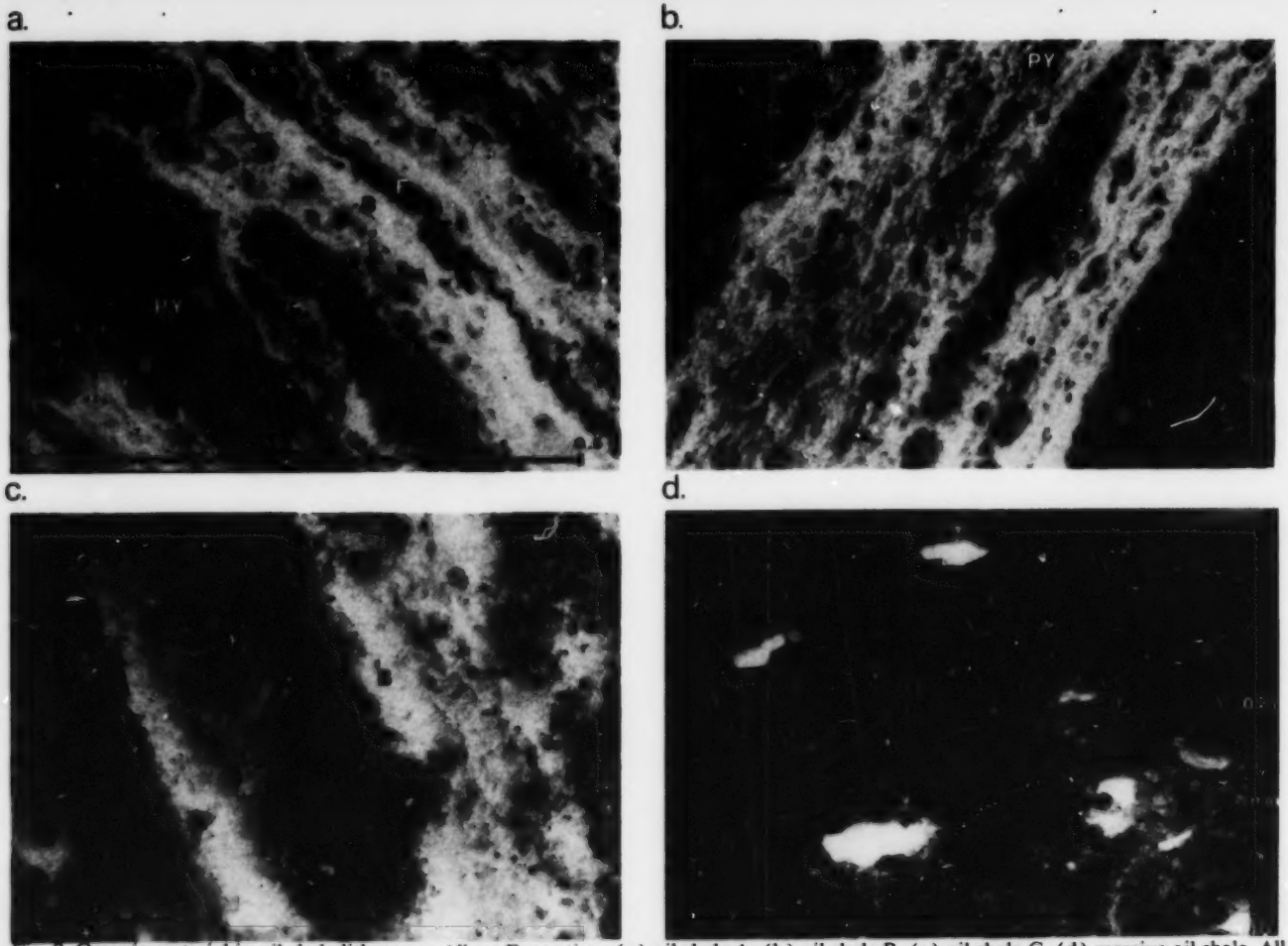

Fig. 9. Organic material in oil shale lithotypes, Albert Formation; (a) oil shale A, (b) oil shale B, (c) oil shale C, (d) massive oil shale. All pictures are photomicrographs of polished grain mount samples taken in fluorescence mode. *B*=lamalginite, *L*=liptodetrinite, *S*=sporinite, *F*=fusinite and *PY*=pyrite. Brightly fluorescing masses are telalginite. Scale (in mm) shown in Figs. 9a,d.

Smith (1985) and Smith and Gibling (1987) carried out Rock-Eval analyses on their oil shale lithotypes. It is seen from a modified van Krevelen diagram (Fig. 10) that oil shale A is characterized by organic matter Type I-IIA (Type I of Tissot and Welte, 1984), oil shale B is characterized by Type IIA (Type II of Tissot and Welte, 1984), oil shale C is characterized by Type IIA-IIB, (Type II of Tissot and Welte, 1984) and massive oil shale is characterized by Type IIA.

The trends on the modified van Krevelen diagram are generally consistent with the organic petrography studies and reflect the maceral composition. Type I organic matter, largely derived from algal precursors (Barnes et al., 1984; Tissot and Welte, 1984), was expected for lithotype A based on the preponderance of microscopically observed lamalginite (Table 6). The Type II (IIA–IIB) trend, usually associated with organic matter found in marine sediments (Tissot and Welte, 1984; Altebaumer, 1985), reflects, as is apparently the case for the Albert oil shales B and C and massive oil shale, a mixture of alginitic, liptinitic and aromatic-rich higher plant sources (Barnes et al., 1984; Mukhopadhyay, 1989). In contrast, organic-poor mudstones and siltstones associated with oil shales in the southeastern part of the Moncton Subbasin typically contain mostly Type IIB-III and IV organic matter (Fig. 10). The organic matter in these rocks is derived mainly from detrital liptinitic mate-

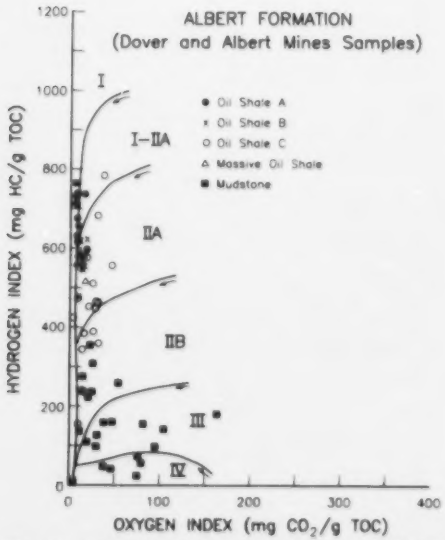

Fig. 10. A plot of hydrogen index (mg HC/g TOC) versus oxygen index (mg CO_2/g TOC) (modified from Espitalie et al., 1977 and Mukhopadhyay, 1989) showing various organic matter types for the Albert oil shale lithotypes; data from Smith (1985). Associated lithotypes are shown for comparison.

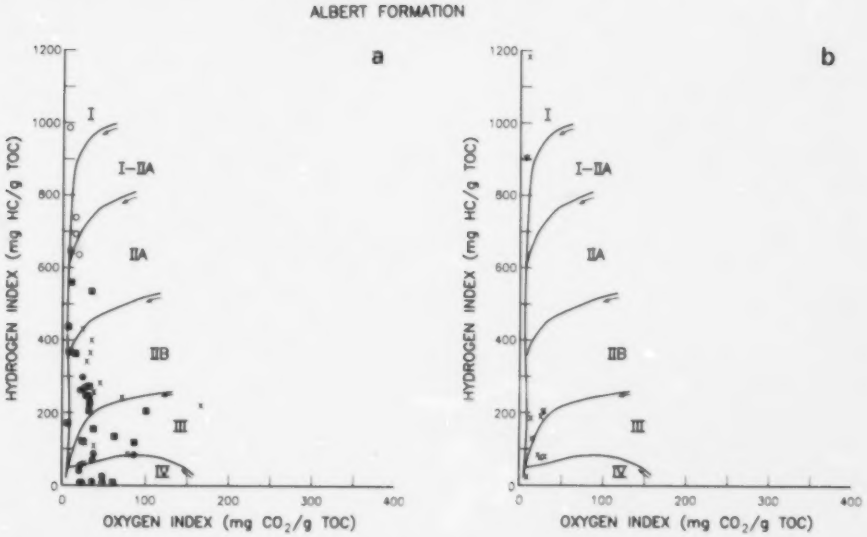

Fig. 11. A plot of hydrogen index (mg HC/g TOC) versus oxygen index (mg CO_2/g TOC) (modified from Espitalie et al., 1977 and Mukhopadhyay, 1989) showing various organic matter types in Albert rocks sampled from the southwest (Fig. 11a) and northeast (Fig. 11b) parts of the Moncton Subbasin; unpublished data from A.H. Chowdhury (pers. commun., 1990). In Fig. 11a squares represent outcrop samples, all other symbols represent drillcore samples.

rial with only minor contribution from terrestrial higher plants. In this case, the Type III and IV trends probably reflect decomposition of carbonate minerals during pyrolysis rather than the true maceral composition (Smith, 1985; Smith and Gibling, 1987), a limitation of the Rock-Eval technique in testing samples with low TOC's noted by other workers as well (e.g. Katz, 1983).

In addition to the data of Smith (1985) and Smith and Gibling (1987), Rock-Eval pyrolysis results are also available on several hundred ditch cuttings, core and outcrop samples of Albert rocks. The data, far too extensive to fully report here, are, in part, included in published reports by Macauley and Ball (1982, 1987) and Brown and Whaley (1986).

Macauley and Ball (1982) reported predominantly Type I organic matter with minor admixtures of Types IIA–IIB and III organics in the oil shales tested from the southeast part of the subbasin. It should be noted that most of the type A and B oil shales analyzed by Smith (1985) are from a drillcore section at Albert Mines and in this regard support the observation of Macauley and Ball (1982), Kalkreuth and Macauley (1984) and Macauley et al. (1985) that the organic matter in the shales at Albert Mines is largely alginitic Type I. Samples obtained by Brown and Whaley (1986) from the southeast part of the subbasin showed, almost exclusively, Type I organic matter.

Recent Rock-Eval pyrolysis testing has also been carried out on Albert oil shale sampled from drill core sections, well cuttings and outcrop of the southwest and northeast parts of the subbasin by A.H. Chowdhury (pers. commun., 1990). The data, presented in Figs. 11a,b, show, based on the samples collected, that organic-rich lamalginitic shales comprise only a minor part of the section in those areas. Of the 43 samples analyzed from the southwestern part of the subbasin, only one clearly contained Type I–IIA organic matter with a TOC content of about 4 wt.%. The remainder of the samples, containing Types IIA, IIB, III and IV organic matter, have an average TOC content of only 1.24 wt.%. In this regard, the differences in the sample suite are analogous to the organic-rich laminated oil shales versus the organic-poor mudstones described by Smith (1985) and Smith and Gibling (1987) in the southeast part of the subbasin (cf. Figs. 10 and 11a).

In the samples from the northeast, organic-poor mudstones yield pyrolysis products indicating mainly Type I and admixed Type IIB and III organic matter (Fig. 11b). The geochemical evidence of limited Type III organic matter agrees with the fact that plant fragments are rarely seen in the laminated dolomitic mudstones in this area.

Gas chromatography

The composition of organic matter in the Albert oil shales from two areas in the southeastern part of the Moncton Subbasin has been investigated by gas chromatography and pyrolysis-gas chromatography (Altebaumer, 1985). Capillary gas chromatography was undertaken on the C_{15+} saturated hydrocarbons for 18 drillcore samples. The C_{15+} extract from samples in one area shows a high content of low molecular weight hydrocarbons ($<C_{21}$) with an odd carbon number preference thus suggesting an algal or bacterial source for the organic matter (Tissot and Welte, 1984).

Pyrolysis-gas chromatography on isolated organic matter from samples showed pyrolysis products to be mainly alkanes and alkenes. The ratios and distribution of the alkanes and alkenes are similar to that of alginite or alginite-rich organic matter (Altebaumer, 1985). Thus, the chromatography data supports the conclusion drawn from the microscopic maceral analyses and the Rock-Eval pyrolysis data; that is, the organic matter in the oil shales in the southeast Moncton Subbasin is primarily derived from algae.

Maturity

Maturation indicators, fluorescence intensity measurements, thermal alteration indices, C_{15+} extracts and vitrinite reflectance data (R_o and R_m for liptinitic-poor sections only), demonstrate that the Albert Formation ranges from slightly immature to overmature with maturation increasing with depth of burial. However, the level of maturity depends somewhat on location.

Fluorescence intensity measurements of lamalginite in drillcore samples of oil shale are reported by Kalkreuth and Macauley (1984). Their studies showed this parameter to be a reliable maturation indicator with values ranging from 544 nm near surface to 700 nm at 700 m depth.

Regional study of thermal alteration indices (T.A.I.) for well cuttings and surface grab samples (35 samples) from across the subbasin by van Helden (1983, unpublished data) showed T.A.I.'s of 2.50–3.75. In particular, the results indicated that surface exposures in the south, southeast and northeast parts of the subbasin were mature for the generation of oil and that maturation increases with depth to within the condensate-dry gas zone.

Extract compositions and yields (C_{15+} fraction) from organic-rich oil shales in the southeast part of the subbasin have been studied by Altebaumer (1985). The data demonstrated that the samples were mature, in accord with the fluorescence intensity and T.A I. data, and that the hydrocarbons intersected in the associated sections from these sites were generated as a result of increasing maturity.

Vitrinite reflectance determinations for oil shale samples have also been reported by Kalkreuth and Macauley (1984) and by Mukhopadhyay (1990). The reflectance of vitrinite particles in the liptinite-rich oil shales is lower than expected, 0.43–0.50% (R_m) and 0.34–0.52% (R_o), suggesting that the sections were immature. However, in liptinitic-poor samples, also studied by Mukhopadhyay (1990), vitrinite reflectance measurements were found to be in agreement with other maturation data with values ranging from 0.40% R_o (near surface) to 1.25% R_o (at depth). Similar lowering of vitrinite reflectance values in Australian oil shales has been attributed to bitumen impregnation of vitrinite (Hutton and Cook, 1980).

The Stoney Creek Oil and Gas Field occurs within Albert sandstones in the southeast part of the Moncton Subbasin (Fig. 3). The oil field was discovered in 1909; it produced a waxy oil for 80 years. Natural gas production ceased in March, 1991. The Stoney Creek crude oil and pyrolized oil (produced from Albert oil shales) both show enrichment in C_{28} and C_{29} sterane biomarkers, thereby upholding the long-held belief that the crude was derived from maturation of the associated shales (Chowdhury and Noble, 1988).

Depositional environments and oil shale composition

Late Devonian/Early Carboniferous fault movements had a controlling influence on the inception of the Moncton Subbasin and accordingly on the distribution of Albert lithofacies. The presence of active faults between the Caledonia Uplift and the subbasin is strongly implied during Albert deposition. The occurrence of organic-rich facies (i.e. oil shale) along the southeast margin of the subbasin at more than one stratigraphic position and in close association with the alluvial fan conglomerates, is evidence of the tectonic

control. Boulder-bearing debris flow conglomerates containing "soft-sediment" intraformational clasts of oil shale are exposed along the south side of the subbasin and indicate that debris flows were deposited directly into a lake.

The confinement of alluvial fan and organic-rich lacustrine facies to the south flank of the Moncton Subbasin implies basinal asymmetry. The south side probably subsided relatively rapidly resulting in significant basin margin relief and deeper lake conditions. In contrast, deposition along the northern margin of the subbasin was more passive (Carter and Pickerill, 1985; Foley, 1989).

Most workers who have studied the Albert Formation oil shales agree that they are of lacustrine origin, based on the predominantly freshwater nektonic biota (e.g. palaeoniscoid fish, abundant algal remains), the continuity and regular thickness of some units, the generally fine grain size and the varve-like laminate (Greiner, 1962,1977; King, 1963; Picard and High, 1972; Pickerill and Carter, 1980; St. Peter, 1982; Pickerill et al., 1985; Smith, 1985).

The Albert lake(s) was/were probably chemically stratified, with oxygenated conditions at the surface and anoxic conditions at depth. Harsh reducing bottom conditions are suggested by the preservation of whole fish skeletons (thus the implied lack of scavengers) and the absence of bioturbation in the oil shales. The lake was also characterized by slightly saline and alkaline water, relatively high energy conditions nearshore and a generally quiescent setting (with occasional density flow deposition) offshore (Smith, 1985). Evidence cited by Smith (1985) to support this interpretation of the lacustrine setting included, in addition to the evidence recognized by other workers, the sedimentary structures, rock colour, mineralogy, geochemistry and organic content of the oil shales and associated strata.

The nearshore lacustrine environment was likely the repository for organic-poor clastic sediments associated with the oil shales. The generally coarse grain size of the associated rock types (i.e. conglomerate, sandstone, siltstone), their sedimentary structures (cross-bedding, starved sand ripples), enclosed mudstone intraclasts and root traces attest to the high energy, shallow water and oxygenated conditions within this environment.

The offshore lacustrine setting (Fig. 12) provided a quiet and anoxic environment that was generally free of coarse clastic input and favoured the preservation of abundant organic matter, clays and carbonates that formed the Albert oil shales. In particular, the richest oil shales, types A and B, were deposited in the "deep" offshore sub-environment and the leanest oil shale, type C, was deposited in the "shallow" offshore sub-environment. All of these oil shale types are finely laminated and fine-grained, contain abundant organic matter and pyrite, and lack features indicative of oxygenated conditions (such as root traces and burrows) thus supporting the interpretation that the oil shale depositional environment was removed from the nearshore lacustrine setting. However, oil shale C contains a significantly lower organic car-

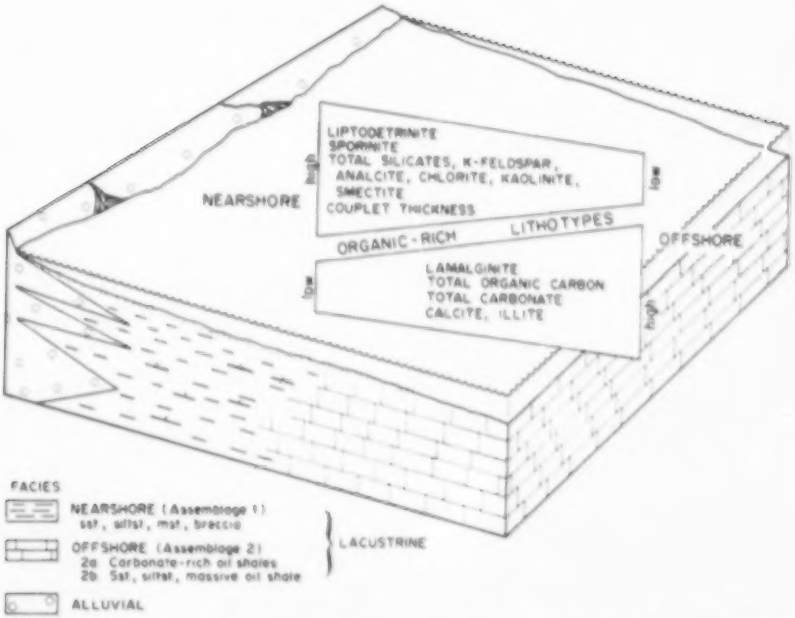

Fig. 12. Diagrammatic illustration of the lacustrine depositional setting of the Albert Formation oil shales and associated lithotypes. The nearshore assemblage includes organic-poor coarse-grained clastic rocks while the offshore assemblage includes the oil shale lithologies and mass flow deposits. The trends shown apply to strata in the vicinity of the Stoney Creek Delta (Dover and Albert Mines) and the Caledonia Uplift, where the precise paleogeography is difficult to infer.

bon content, a higher proportion of liptodetrinite and less continuous and less abundant lamalginite laminae than either oil shale A or B (Table 6, Fig. 8). Locally, oil shale C also contains mudstone intraclasts. Thus, the attributes of oil shale C suggest that it was deposited in an area of the offshore environment that was periodically subjected to moderately high energy conditions. Oil shale C was probably deposited in the upper portion of the anoxic zone in the "shallow" offshore setting, transitional to the nearshore setting of high clastic input and the "deep" offshore setting of the richest oil shales. The conclusion drawn from the physical evidence, that the nearshore lacustrine environment is less reducing than the offshore lacustrine environment, is supported by Altebaumer's (1985) study of pristane/phytane ratios of organic matter extracts from sandy and organic-poor facies and organic-rich oil shale samples. The ratios are greater than 1.0 for samples of the sandy and organic-poor facies and considerably less than 1.0 in the organic-rich facies.

The massive oil shale lithotype, which is rather coarse-grained (clay–silt), non-laminated and rich in organic matter (mixture of liptodetrinite, telalgin-

ite and sporinite with minor fusinite), is also considered to have been deposited in the "deep" offshore lacustrine environment. Massive oil shale is interbedded with sandstone and siltstone and the assemblage is associated with the richer oil shales as shown by Markov Chain analysis (Smith, 1985; Smith and Gibling, 1987). The assemblage was probably emplaced in the "deep" offshore setting by turbidity current deposition of coarse-grained clastic sediment and syn-sedimentary reworking of previously accumulated layers of algae and clay-sized sediment. The possibility for a mass flow mechanism for the emplacement of the massive oil shale, and interbedded clastic sediments, is supported by associated syn-sedimentary features indicating depositional instability, such as: chaotic crenulated/folded laminae in the richer oil shales (King, 1963; Macauley and Ball, 1982; Smith, 1985; Pickerill et al., 1985) and sand-filled injection features cutting organic-poor mudrocks and lean (i.e. type C) oil shales (Smith, 1985; Brown and Whaley, 1986). As well, the relative abundance of telalginite and sporinite in massive oil shale, greater than in oil shale A, B or C, suggests that these macerals were preferentially concentrated during transport, as observed in modern shallow lakes by Livingstone (1985).

The organic content and distinctive mineralogy and chemistry of the oil shales supports the suggestion that the lacustrine environment was alkaline and slightly saline. The predominant maceral in the oil shales, lamalginite, is similar to that derived from *Pediastrium* in the Thai oil shales described by Sherwood et al. (1984). *Pediastrium* is a freshwater alga with a low salinity tolerance, about 1.7 g/l (Singh et al., 1981). The "deep" lacustrine strata, especially the organic-rich oil shales, are characterized by a distinctive mineralogy and chemistry. The "deep" shales (A, B and massive) contain more calcite and illite than the "shallow" oil shale C (Table 2). The "deep" sequences contain less dolomite, smectite, kaolinite and chlorite than the "shallow" lake beds. The "deep" lacustrine oil shales contain no analcite unlike their "shallow" lake counterparts (Table 2). The major element compositions support the mineralogical findings. The "deep" lacustrine deposits contain greater CaO and P_2O_5 and less MgO, Fe_2O_3, Na_2O and K_2O than the typical "shallow" lake oil shale C (Table 3, Fig. 7).

The most significant aspect of the oil shale mineralogy is the abundance of carbonate minerals (mainly calcite and dolomite). Carbonates comprise about 20% to as much as 95.6% of the inorganic component and are believed to have formed in an alkaline environment as a result of precipitation or early diagenesis. Textural observations, namely (1) calcite and dolomite exist in the oil shales as micrite, (2) the delicate laminae are not disturbed by disruptive or displacive diagenetic mineral growth and (3) well-formed carbonate grains can be seen with the aid of the scanning electron microscope to be suspended in the organic matter, support the interpretation that the carbonates were syngenetic or early diagenetic.

The greater abundance of dolomite, Mg and Fe in the oil shale of the "shallow" offshore environment and the greater abundance of calcite and Ca in the oil shales of the "deep" offshore environment requires some comment. Whether the carbonate is calcite or dolomite largely depends upon the availability of Mg since $MgCaCO_3$ and $CaCO_3$ should form under alkaline conditions (Reeves, 1968; Brobst and Tucker, 1973). Conditions for dolomite formation were apparently most favourable in the "shallow" offshore lacustrine environment where oil shale C and associated dolostone are most abundant. Some of the Mg may have been incorporated within the original algal material (Gebelein and Hoffman, 1973; Desborough, 1978) and because of the fragmented state of the organic matter and the less reducing conditions in the "shallow" offshore setting, Mg may have been more easily liberated from the organic matter and, thus, more readily available to form dolomite. In the "deep" offshore sediments the algal material was preserved essentially intact in a reducing environment.

One must also speculate about the effect that siliclastic input may have had on calcite production. The closer proximity of the "shallow" offshore setting to nearshore areas may have resulted in decreased algal productivity as a result of clastic input and consequently lower biogenic calcite precipitation. In contrast to trends observed from the Albert oil shales, studies in modern Lake Balatron by Muller and Wagner (1978) showed that Mg^{2+}/Ca^{2+} ratios in lake water and $MgCO_3$ content in high Mg-calcite increase offshore.

The lacustrine environment probably did not exist as a continuum throughout Albert time. The organic-rich oil shales, like the conglomerate facies, are restricted to the southeastern part of the subbasin. The fact that the oil shales occur as "tongues" at several stratigraphic positions within the formation suggest that, (1) the oil shales may not have been confined to a single basin-wide lake as proposed by Greiner (1974) and (2) the aerial extent of the lake(s) varied through time. For example, the presence of relatively high TOC and well preserved algal-derived laminae in the oil shales of the southeast part of the subbasin implies a deep and possibly permanently stratified lake. Elsewhere, lower TOC and alginite contents and significantly higher liptodetrinite, sporinite, vitrinite and clastic detritus suggests possibly shallower or more ephemeral lake conditions.

STELLARTON FORMATION OIL SHALES

Stratigraphy

The Stellarton Formation comprises the major stratigraphic unit within the Stellarton Basin with exposure of progressively younger beds from the western to the eastern end of the basin (Fig. 13). The formation contains more than 35 coal seams, which range in thickness from 0.1 to 13.4 m, and 60 oil

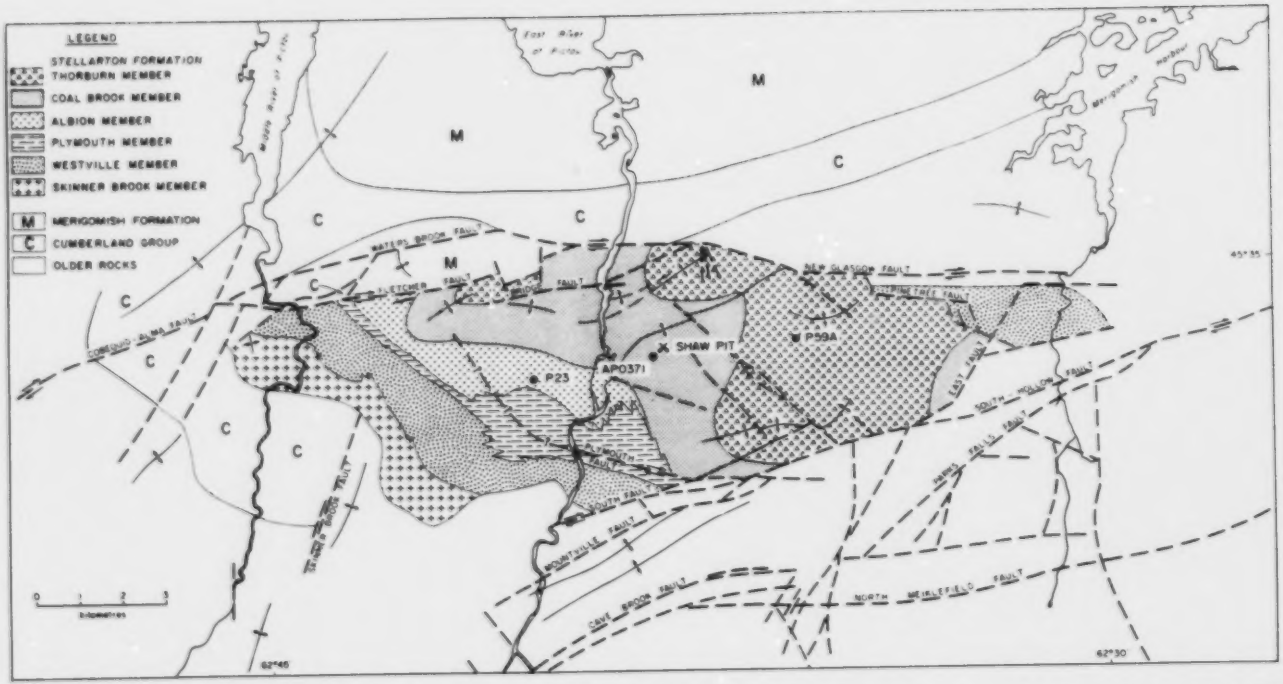

Fig. 13. Geology of the Stellarton Basin, Nova Scotia; modified after Yeo and Ruixiang (1987). The Merigomish Formation, exposed to the north of the basin contains coal and oil shale and is, in part, age equivalent to the Stellarton Formation. Drillholes identified relate to sections described in Fig. 22.

shale beds, varying in thickness from 1 to 45 m (Naylor et al., 1989a). The oil shales form about 18% of the Stellarton Formation overall but are concentrated within the upper half of the formation where, locally, they account for up to 45% of the section.

The Stellarton Formation is divided into two red bed members, Skinner Brook and Plymouth, and four coal- and oil shale-bearing members, Westville, Albion, Coal Brook and Thorburn (Bell, 1940) (Fig. 14a). A probable Westphalian B age for the lower part of the Skinner Brook Member, an early Westphalian C age for the Westville Member, a late Westphalian C age for the Albion Member and an early Westphalian D age for the Thorburn Member have been determined by recent palynological investigations (Dolby 1986a,b; Yeo et al., 1988a).

The red bed members, the Skinner Brook and Plymouth, are distinguished primarily on the basis of stratigraphic position (Fig. 14a,b). The Skinner Brook Member underlies, and is in diachronous contact with, the lower 300 m of the Westville Member. The Plymouth Member is in diachronous contact with the top of the Westville Member, all of the Albion Member and the base of the Coal Brook Member. Both red bed members comprise red sandstone, mudrock and, locally, conglomerate. Mudrock and sandstone are pervasive; they are frequently bioturbated and paleosols are common.

The Albion and Westville Members (Fig. 14b) contain thick (up to 13.4 m thick) coals which are closely associated with oil shale beds. The coals are thickest near central basin areas and grade laterally to carbonaceous shale towards the basin margins. The oil shales often directly overlie or underlie coal seams or form parting(s) within seams. Mudrock and sandstone are interbedded with the oil shales and coals and are generally extensively bioturbated by roots.

The Coal Brook and Thorburn Members possess relatively thin coals that thicken in basin margin areas and thin towards central basin areas, passing laterally into oil shales. In the central basin area, the Coal Brook Member comprises mainly oil shale interbedded with rhythmically layered mudrock and minor fine-grained sandstone (Fig. 14b). Closer to basin margin areas, the oil shales thin and the rhythmically layered mudrocks pass laterally into sequences of sandstone and siltstone which in turn pass into conglomerate sequences directly adjacent to basin margins. The Coal Brook Member contains the thickest and most extensive development of oil shale. In the central basin area, the member is about 500 m thick with oil shale constituting 45% of the section (Fig. 14b); the total area underlain by the Coal Brook Member is approximately 27.5 km^2. Neither the Thorburn or Coal Brook Member exhibit the extensive bioturbation observed in the Albion and Westville Members.

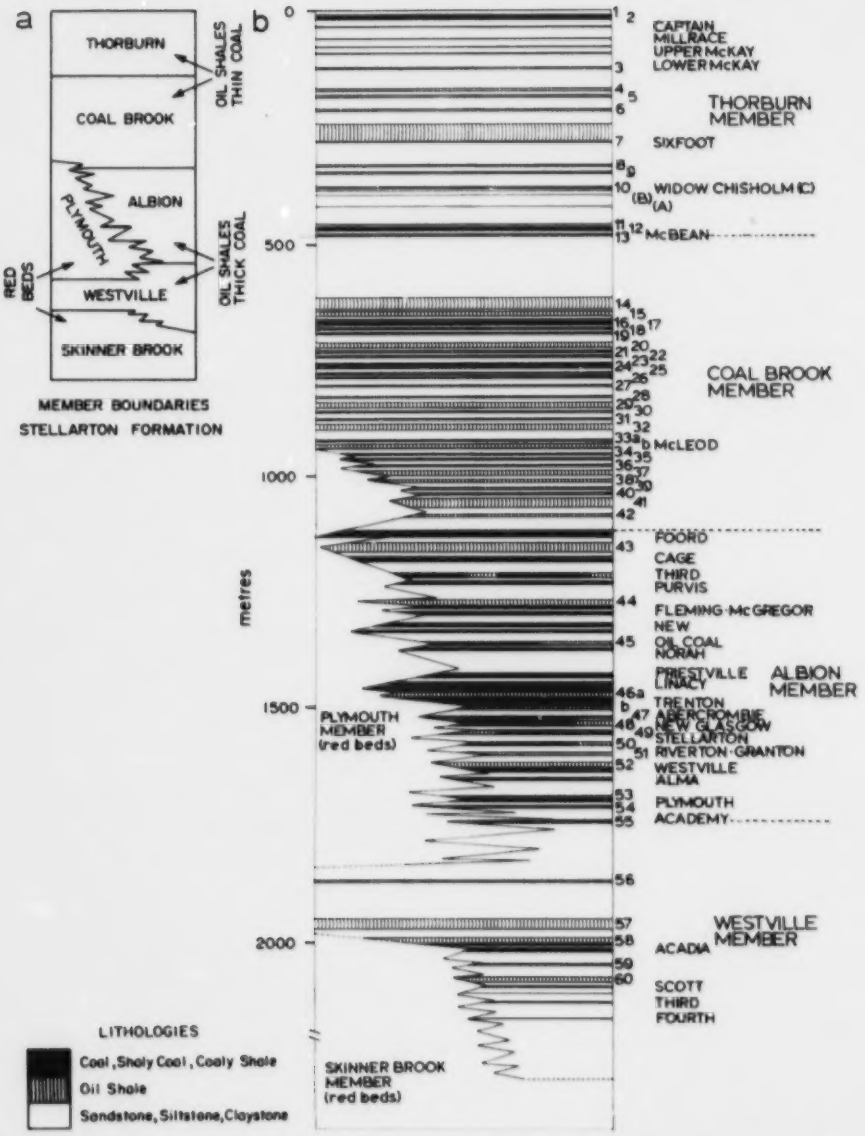

Fig. 14. Stratigraphy of the Stellarton Formation, Nova Scotia showing the subdivision of the formation into members (Fig. 14a) (Bell, 1940) and the detailed stratigraphy (Fig. 14b) (from Smith et al., 1989).

Oil shale lithology

Three lithotypes form the Stellarton oil shale beds: fissile oil shale, blocky oil shale and stellarite oil shale (Naylor et al., 1987; Kalkreuth et al., 1988; Yeo et al., 1988b) (Table 7, Fig. 15). The fissile oil shale (Fig. 15a) weathers easily and tends to split readily along bedding planes. This oil shale lithotype is typically dark grey to black in colour, gives a waxy light brown to dark brown streak and has an average specific gravity of 2.61. Fissile oil shale is the most common oil shale lithotype and comprises a large portion of virtually every oil shale bed. Blocky oil shale (Fig. 15b) is recognized by a massive appearance, conchoidal fracture style, black colour with a bluish or greasy lustre, rare vitrainous coaly laminae and a waxy dark brown to black streak. Blocky oil shale has an average specific gravity of 2.37. Blocky oil shale forms part of most oil shale beds (Table 7, Fig. 14b) but accounts for only thin sections (≤ 30 cm) and a small proportion of the oil shale beds overall. Stellarite oil shale (Fig. 15c) is typically grey to brownish black in colour has a powdery yellow brown streak and an average specific gravity of 1.81. Stellarite contains small (millimetre-scale) ellipsoidal and amber-coloured "grains" which are concentrated locally forming thin bands that fluoresce and give the rock a banded appearance when exposed to long wavelength ultra-violet light

TABLE 7

Stellarton Formation oil shale lithotypes (modified after Smith, Naylor and Kalkreuth (1989)

Physical and technical properties	Fissile oil shale	Blocky oil shale	Stellarite oil shale
Colour and appearance	Dark grey to black spilts readily; weathers easily; gives a waxy light brown to dark brown streak	Black with a bluish or greasy lustre; abundant vitrainous coaly laminae; resists fracture; conchoidal fracture style; gives a waxy dark brown to black streak	Grey to brownish black; contains mm-scale ellipsoidal amber grains concentrated locally into bands which fluoresce under UV light and give the rock a banded appearance; gives a powdery yellow-brown streak
Fossils	All contain *Cordaites* sp., *Lepidostrobus* sp., *Trigonocarpus* sp., fish remains (spines, teeth, scales, fecal pellets) and ostracods. Pelecypods (*Anthraconauta* sp.) are common in fissile oil shale		
Specific gravity	2.61 (Average, 63 samples)	2.374 (Average, 18 samples)	1.807 (Average, 18 samples)
Relative abundance within Stellarton Formation	Most common oil shale type; known to all 60 oil shale beds	Comprises thin sections (30 cm or less) of most of the 60 oil shale beds	Known to only 6/60 oil shale beds as 0.15–1.85 m thick sections

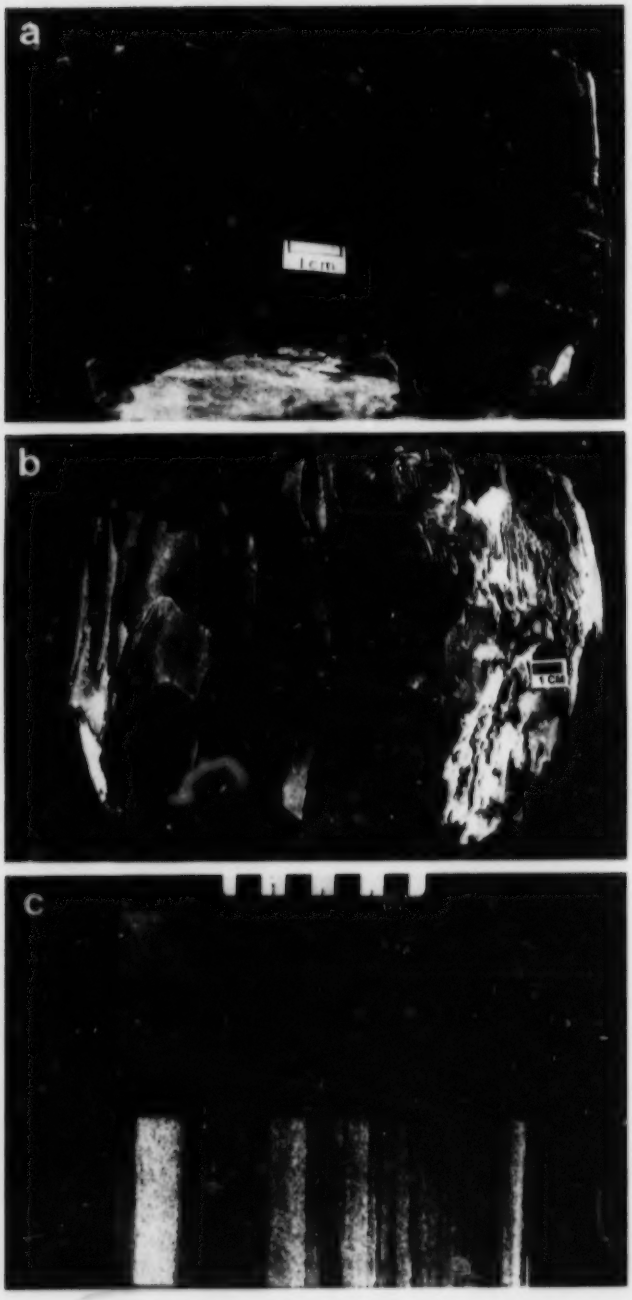

Fig. 15. Oil shale lithotypes, Stellarton Formation, Stellarton Basin, Nova Scotia. (a) Fissile oil shale showing well developed fissility, (b) blocky oil shale showing its typical conchoidal fracture style, (c) stellarite oil shale at top showing appearance in ordinary light (wide strip is the residue of masking tape used to hold the section together) and immediately below under long wavelength ultra-violet light, the remains of *Botryococcus* sp. are concentrated locally such that the stellarite shows a banded and graded appearance.

(Kalkreuth et al., 1990). Stellarite oil shale can be ignited with an open flame (Macauley and Ball, 1984) and forms 0.15–1.85 m thick beds.

All three oil shale lithologies contain an abundant fossil floral assemblage including *Cordaites* sp., *Lepidostrobus* sp. and *Trigonocarpus* sp. Fossil fauna include *Anthroconauta* sp. in the fissile oil shales and fish remains (spines, teeth, scales), fecal pellets and ostracods in all three lithologies. The stellarite oil shales are especially rich in fish remains and fecal pellets.

Oil shale composition

Inorganic composition

Mineralogical analyses (XRD: Macauley and Ball, 1984; Smith and Naylor, 1990; SEM-EDX: Naylor and Smith, 1986; Infrared Spectroscopy: Naylor et al., 1989b) show all the oil shale lithotypes to be silicate-rich comprising mostly clays and quartz with minor carbonate and trace sulfide minerals. The clay minerals are dominated by illite with trace smectite, kaolinite and chlorite. Quartz is present as subangular to subrounded grains 20 μm in size. Siderite with trace calcite and dolomite (up to 20 μm in size) average 5%, up to 25% locally, of the inorganic component. Sulfide minerals include pyrite (grains 10 μm in size forming nodules and lenses and finely disseminated), chalcopyrite, sphalerite and galena. Rutile, apatite and gypsum are also reported locally.

Elemental analyses were conducted by Naylor and Smith (1986) using neutron activation and by Naylor et al. (1989b) using inductive coupled plasma (ICP). The analyses show variation in relation to primary enrichments in the organic matter (Cu, Zn, Ag, Ni), detrital input (Ti, Zr) and depth of deposition (V, Cr). The elemental abundances, with a few excep-

TABLE 8

Selected trace element chemistry (in ppm) of Stellarton Formation oil shales relative to the crustal average cited by Mason and Moore (1982) and relative to average black shale cited by Vine and Tourtelot (1970)

Sample no.	Oil Shale bed	As	B	Cs	Mo	Sb	Se
	Crust	1.80	10.00	3.00	1.50	0.20	0.05
	Average black shale	No data	50.00	No data	10.00	No data	No data
WSP-89-03	Oil shale #58	25.00	100.00	11.00	1.00	1.20	0.50
NSP-84-72-19	Oil shale #22	23.00	60.00	9.50	7.00	0.90	2.70
NSP-84-73-11	Oil shale #22	17.00	80.00	13.60	7.00	1.30	2.70
NSP-84-73-26 to 28	Oil shale #22	16.00	80.00	18.00	8.00	1.80	3.20
NSP-84-73-38	Oil shale #22	11.00	90.00	17.10	6.00	1.40	0.60
NSP-85-16	Oil shale #33b	17.00	60.00	15.70	7.00	1.10	4.00
NSP-84-72-13	Oil shale #22	20.00	70.00	15.60	8.00	1.40	3.30

tions, are comparable with values for the crustal average cited by Mason and Moore (1982). Silica is the most abundant element in the oil shales followed by (in order of decreasing abundance) Al, Fe, K, Ca, Mg, Ti and Na. However, As, B, Cs, Mo, Sb and Se are recorded at levels near six times the crustal average for some samples (Table 8). Data from Vine and Tourtelot (1970) show B and Mo values for average black shales comparable to those obtained in this study.

Organic composition

Studies of total organic carbon (TOC) content, organic petrography, Rock-Eval pyrolysis and gas chromatography have been carried out by Macauley and Ball (1984), Chevron (1986), Hutton (1986), Naylor and Smith (1986), Kalkreuth and Macauley (1987), Paul (1988), Puttmann and Kalkreuth (1989), Mukhopadhyay et al. (1990) and Smith and Naylor (1990). Additional samples have also been analyzed in this study.

The analyses were conducted on samples from drillcore and outcrop and the t-test of Imbrie (1956) applied to the data to determine the significance of observed compositional differences between oil shale types. Thus, only trends supported by statistical analyses are presented in the following sections.

TOC and maceral content

The total organic carbon (TOC) content has been determined for 46 of 60 oil shale beds (364 samples) and maceral analyses have been conducted on 32 of 60 oil shale beds (158 samples). The data are summarized in Table 9 and Fig. 16 in relation to oil shale lithology.

Beds comprising mainly fissile oil shale are low in organic content (average = 4.9 wt.% TOC). The organic matter is material of terrestrial origin (i.e. vitrinite + inertinite + sporinite + cutinite: 55.9 vol.%, on average) and fluorescing liptinitic groundmass material of either terrestrial and/or aquatic affinity (42.4 vol.%, on average). The fluorescing liptinitic groundmass material includes bituminite of Stach et al. (1982) and mineral bituminous groundmass of Teichmüller (1986) (Table 9, Figs. 16,17a). These oil shales have the lowest content of telalginite of the three oil shale types (up to 5.3 vol.%, average 1.7 vol.%).

Beds rich in blocky oil shale contain the highest level of organic matter, with values up to 43.5 wt.% TOC but 9.0 wt.% on average. The organic matter comprises fluorescing liptinitic groundmass material (average = 51.2 vol.%) and material of terrestrial origin (average = 42.2 vol.%) with minor telalginite (average 6.3 vol.%) (Table 9, Figs. 16, 17b). Locally, where TOC is elevated, sections of these oil shale beds contain high levels of vitrinite (up to 88.0 vol.%) and therefore may be classed, on the basis of Hutton's (1987) petrographic classification of oil shales, as cannel shale.

Beds rich in stellarite oil shale show the highest average content of organic

TABLE 9

Total organic carbon (in wt.%) and maceral data (mineral matter free) in relation to oil shale lithotype, Stellarton Formation. *T.O.C.* = total organic carbon, *F.L.G.* = fluorescing liptinitic groundmass, *Telalg.* = telalginite, *Spor + Cut* = total sporinite and cutinite, *Oth Ex + Vit + In.* = total of sporinite, cutinite, vitrinites and inertinites. *Std. dev.* = standard deviation

Lithology		T.O.C.	F.L.G.	Telalg.	Spor. + Cut.	Vitrinite	Inertinite	Oth Ex + Vit + In
Oil shale beds rich in fissile oil shale	Range	1–11.5	7.7–92.9	0–5.3	1.7–45.2	3.0–66.7	1.0–30.8	6.72–92.40
	Mean	4.9	42.4	1.7	17.5	23.8	14.6	55.89
	Std.Dev.	2.4	24.3	2.2	13.6	20.3	9.7	23.84
	No. of samples	64	11	11	11	11	11	11
Oil shale beds rich in blocky oil shale or assoc. with coal	Range	0.3–43.5	0–99.0	0–52.2	0–68.8	0–88.0	0–23.9	0.1–120.3
	Mean	9.0	51.9	6.4	15.3	19.1	8.0	42.43
	Std. Dev.	8.0	26.6	9.3	13.6	19.3	6.0	25.84
	No. of samples	268	131	131	131	131	131	131
Oil shale beds rich in stellarite oil shale	Range	0.3–28.2	0–99.0	0–97.0	0–11.5	0–36.8	0–23.7	0.15–63.10
	Mean	12.0	68.2	17.2	3.3	6.7	4.7	14.69
	Std. Dev.	7.6	27.4	25.9	3.7	11.1	6.5	18.93
	No. of samples	32	16	16	16	16	16	16

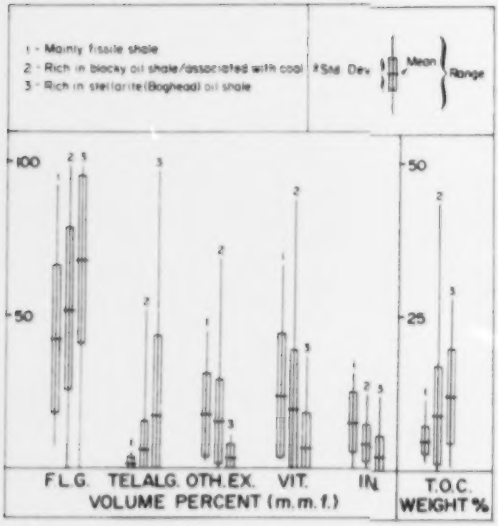

Fig. 16. Total organic carbon (TOC) content and organic petrology data in relation to oil shale lithotype, Stellarton Formation. *F.L.G.* = fluorescing liptinitic groundmass, *TE-LALG.* = telalginite, *OTH.EX.* = other exinites (sporinite, cutinite), *VIT.* = total vitrinite, *IN.* = total inertinite, m.m.f. = mineral matter free.

carbon (average = 12.0 wt.%). The organic matter is rich in telalginite (up to 97 vol.% and on average 17.2 vol.%) and fluorescing liptinitic groundmass material (average = 68.2 vol.%) (Table 9, Figs. 16,17c). Material of terrestrial origin generally accounts for a minor portion of the organic component (average = 14.6 vol.%). On the basis of Hutton's (1987) petrographic classification of oil shales, stellarites may be classified as boghead shales.

Rock-Eval pyrolysis

Rock-Eval pyrolysis has been conducted on 369 samples representing 46 of the 60 oil shale beds. The results vary for any given oil shale type, but some trends, supported by the t-test, are apparent. The data are summarized in Table 10.

Stellarite oil shales show the highest mean hydrogen indices (S_2/TOC = 519), fissile oil shales the lowest indices (226), and blocky oil shales intermediate values (320). All oil shale lithologies have generally low (less than 100) oxygen indices (S_3/TOC) with average values of 18.5. Plotted on a modified van Krevelen diagram (Fig. 18), 75% of the samples fall within the Type IIB zone with the remainder plotting within the Type IIA (12%), Type I (7%) and Type III (6%) zones. The results are in accord with the petrographic data and reflect the maceral trends outlined above. Samples

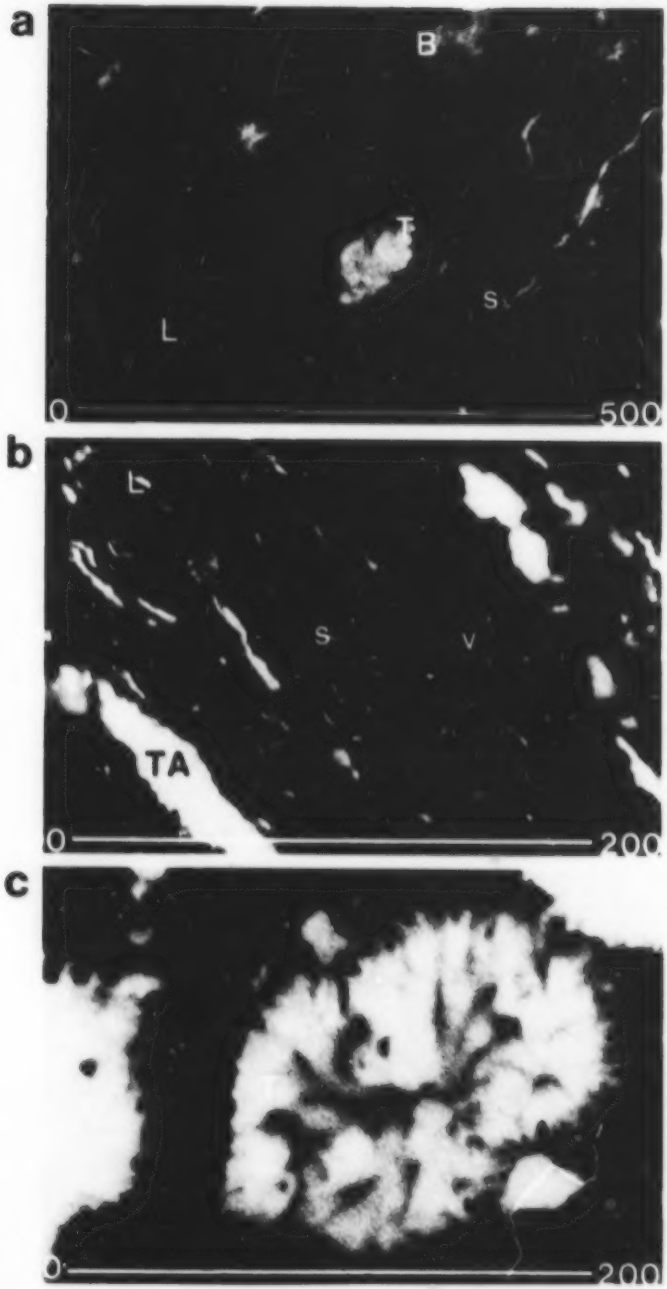

Fig. 17. Organic material in oil shale lithotypes, Stellarton Formation; (a) fissile oil shale, (b) blocky oil shale, (c) stellarite oil shale. All pictures are photomicrographs of polished grain mount samples taken in fluorescence mode. *TA/T* = telalginite, *B* = fluorescing liptinitic groundmass, *L* = liptodetrinite, *S* = sporinite and *V* = vitrinite. Scales shown are in μm.

TABLE 10

Rock-Eval pyrolysis data in relation to oil shale lithotype, Stellarton Formation. S_1+S_2 = hydrocarbon yield potential (mg hydrocarbons/g rock). *Std.Dev.* = standard deviation. Calculated yield is in litres per tonne

Lithology		Hydrogen index	Oxygen index	S_1+S_2	Calculated yield	T_{max}	Production index
Oil shale beds rich in fissile oil shale	Range	38–617	4.5–42	1.38–34.86	1.2–30.7	438–509	0.03–0.30
	Mean	226	17.5	12.31	9.6	452	0.11
	Std. Dev.	98	8.5	8.03	6.3	12	0.04
	No. of samples	64	18	64	64	64	64
Oil shale beds rich in blocky oil shale or assoc. with coal	Range	7–1160	0–113	0–186.88	0–148.7	435–538	0.00–0.21
	Mean	320	18	32.90	27.4	450	0.08
	Std. Dev.	163	19	33.97	26.5	8	0.03
	No. of samples	268	221	273	257	273	273
Oil shale beds rich in Stellarite oil shale	Range	30–957	1–244	0.22–272.03	0.2–201.3	440–523	0.00–0.20
	Mean	519	25	80.59	67.1	453	0.04
	Std. Dev.	322	50	72.27	58.6	8	0.05
	No. of samples	32	25	32	32	273	32
All oil shales	Range	not calculated	0–244	not calculated	not calculated	435–538	Not calculated
	Mean		18.5			450	
	Std. Dev.		23.5			9.50	
	No. of samples		264			369	

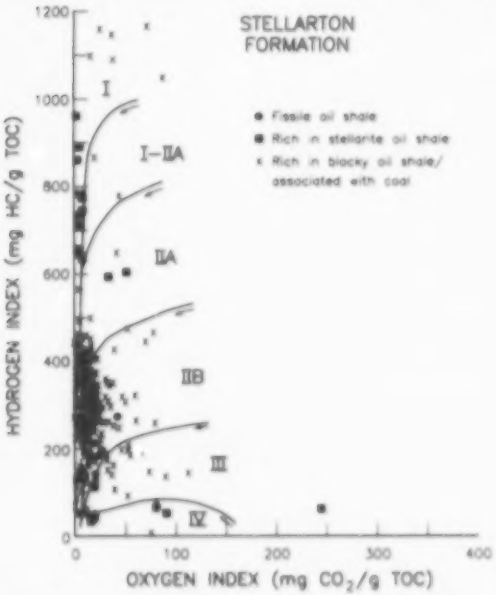

Fig. 18. A plot of hydrogen index (mg HC/g TOC) versus oxygen index (mg CO_2/g TOC) (modified from Espitalie et al., 1977 and Mukhopadhyay, 1989) showing various organic matter types for the Stellarton oil shale lithotypes.

within the Type IIA–IIB zone (fissile oil shales, most blocky oil shales and some of the stellarite oil shales) reflect the mixed maceral assemblage of fluorescing liptinitic groundmass and terrestrial organic matter. Samples in the Type I zone represent alginite- (i.e. telalginite) rich organic matter while those in the Type I–IIA zone represent a mature alginite-rich organic component or a mixture of alginite and fluorescing liptinitic groundmass material. Samples which plot in the Type I and the Type I–IIA zones are stellarite oil shales and minor blocky oil shale. Samples in the Type III zone typically represent the organic-rich blocky oil shales (cannel shales) containing relatively more vitrinite.

Potential hydrocarbon yields (S_1+S_2) range from 0–272 mg/g and appear to correlate with hydrogen indices (Fig. 19). Beds comprising mainly fissile oil shale have the lowest average hydrocarbon yield potential (12.3 mg/g), beds rich in blocky oil shale are of intermediate potential (average = 32.9 mg/g) and beds rich in stellarite oil shale give the highest potential (up to 272 mg/g; average = 80.6 mg/g).

Gas chromatography

Gas chromatography analyses conducted on 19 samples that include fissile oil shale, blocky oil shale and stellarite oil shale (representing 6 of the 60 oil

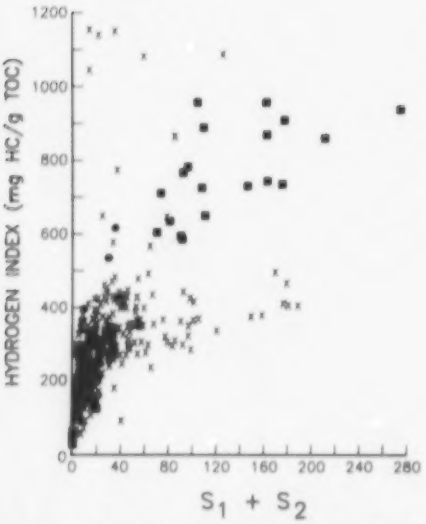

Fig. 19. A plot of hydrogen index (mg HC/g TOC) versus hydrocarbon yield potential ($S_1 + S_2$) showing the trends in yield for the various Stellarton oil shale lithotypes. See Figs. 16, 18 for legend.

shale beds) show a difference in the liquid products derived from the different oil shale types. Fissile oil shale gave Pr/Ph ratios of 1.8–2.9 (average = 2.44) and Pr/nC_{17} values of 0.17–0.44 (average = 0.25). Blocky oil shale generally gave Pr/Ph ratios of 1.89–9.82 (average = 3.86) and Pr/nC_{17} values of 0.16–0.75 (average = 0.43). However, one sample of blocky oil shale gave a Pr/Ph ratio of 1.3 and a Pr/nC_{17} value of 2.69. Stellarite oil shale gave a Pr/Ph ratio of 4.1 and a Pr/nC_{17} value of 1.07. Gas chromatography data for coals of the same sequence (2 coal seams: 19 samples) gave Pr/Ph ratios of 2.89–9.59 (average = 6.17) and Pr/nC_{17} values of 0.16–0.83 (average = 0.53). Except for one sample, the blocky oil shale samples are most comparable with coal in terms of Pr/Ph and Pr/nC_{17} ratios which suggests that they are closely related to coal in terms of depositional setting and organic source.

Maturity

Maturation indicators, T_{max} and Production Index, reveal that the Stellarton oil shales are at a mature to overmature stage of thermal diagenesis (Fig. 20). The overmature samples were obtained from drillcore depths in excess of 1200 m and they indicate that maturation of the sediments in the basin is depth-controlled, an observation made by Hacquebard and Donaldson

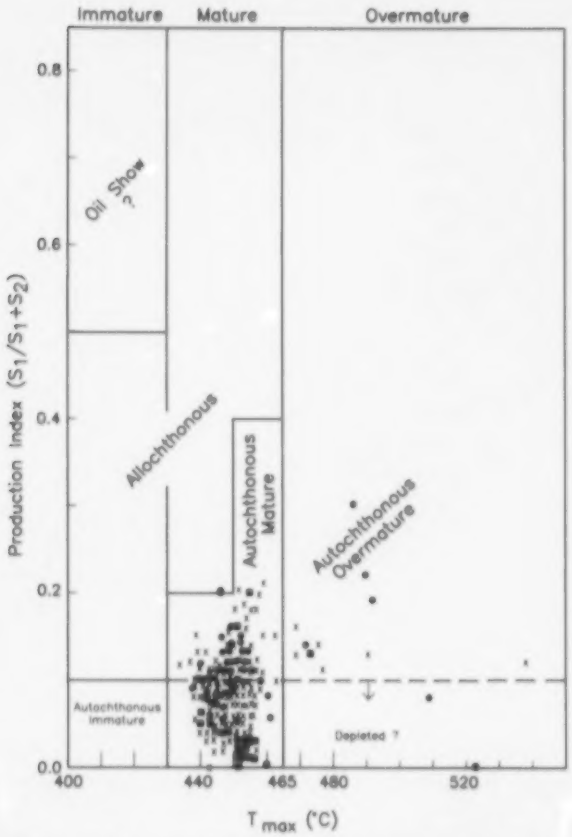

Fig. 20. A plot of Rock-Eval maturation indicators, Production Index (S_1/S_2+S_2) versus T_{max} (°C). for the Stellarton oil shales showing that they are at a mature to overmature stage of thermal diagenesis. Some of the samples plot within the zone of hydrocarbon expulsion. See Figs. 16, 18 for legend.

(1970). Vitrinite reflectance data for 57 samples of Stellarton oil shale gave values of 0.38–1.04 R_o indicating immature to mature sediments. The vitrinite reflectance values are not in agreement with the Rock-Eval maturation data. The measured T_{max} data range from 435 to 538°C equivalent to R_o values of 0.50 to in excess of 1.35 on the basis of a kerogen maturation diagram (Espitalie et al., 1985). The equivalent R_o values from the T_{max} data thus suggest that the measured R_o values are too low. The discrepancy here, as with the Albert Formation oil shales, is attributed to lowered reflectance of vitrinite in oil shales that contain a relatively high percentage of liptinite macerals.

The maturation parameters suggest that many of the oil shales have expelled hydrocarbons as a result of catagenesis. However, carbon isotope analyses of liquid extracts from coal and oil shale samples and oil shows within the formation suggest that the coals of the formation, not the oil shales, are the source rock (MacDonald et al., 1990; Mukhopadhyay et al., 1990).

Depositional environments and oil shale composition

The Stellarton Basin developed in Late Westphalian B and was a rapidly subsiding depocentre until at least the Early Westphalian D (Yeo and Ruixiang, 1987; Naylor et al., 1989a). Most workers who have studied the basin-fill agree that the oil shales of the sequence were deposited in a lacustrine environment (e.g. Hacquebard and Donaldson, 1969; Naylor et al., 1986; Yeo and Ruixiang, 1987; Snow, 1988; Naylor et al., 1989a; Smith and Naylor, 1990). Evidence cited for a lacustrine interpretation include the remains of *Botryococcus* sp., a fresh-to-brackish water alga (Hunt, 1979), and the finely-banded nature of the associated coals (Hacquebard and Donaldson, 1969). Also, the prevailing greyish rock colour, generally fine-grain size, even and regular varve-like nature of associated claystones and the lack of marine fossils are consistent with a lacustrine environment (Picard and High, 1972).

Naylor et al. (1989a) have suggested that the development of lakes within the basin was largely controlled by basin subsidence. Shallow lakes formed when basin subsidence rates were slow, such as during deposition of the Albion and Westville Members. These lakes were readily infilled by lacustrine delta deposits which provided a stable substrate for development of poorly drained and peat forming swamps (mires). The mires were flooded regularly as suggested by the microbanded appearance of the coals and the presence of oil shale and claystone partings. The organic-rich muds that were the precursors of the oil shales were deposited when sediment supply to the basin became restricted. The occurrence of red beds (Plymouth and Skinner Brook Members) in diachronous contact with lacustrine and coal swamp deposits of the Westville and Albion Members indicate that oxidation and soil forming processes were important in the basin margin areas.

Oil shales contained within the Albion and Westville Members include mainly fissile and blocky oil shale lithologies; only one significant occurrence of stellarite oil shale is known. These oil shales were deposited in stratified lakes with oxygenated surface waters and anoxic and reducing conditions within the bottom waters/sediment. Evidence for oxygenated surface waters include the occurrence of fish remains, pelecypods and ostracods within oil shale beds. Anoxic and reducing bottom conditions are suggested by the lack of a burrowing benthos and the presence of common diagenetic minerals formed in a reducing environment such as siderite and pyrite. The gas chromatography results with low Pr/nC_{17} ratios (average 0.25 for fissile oil shale

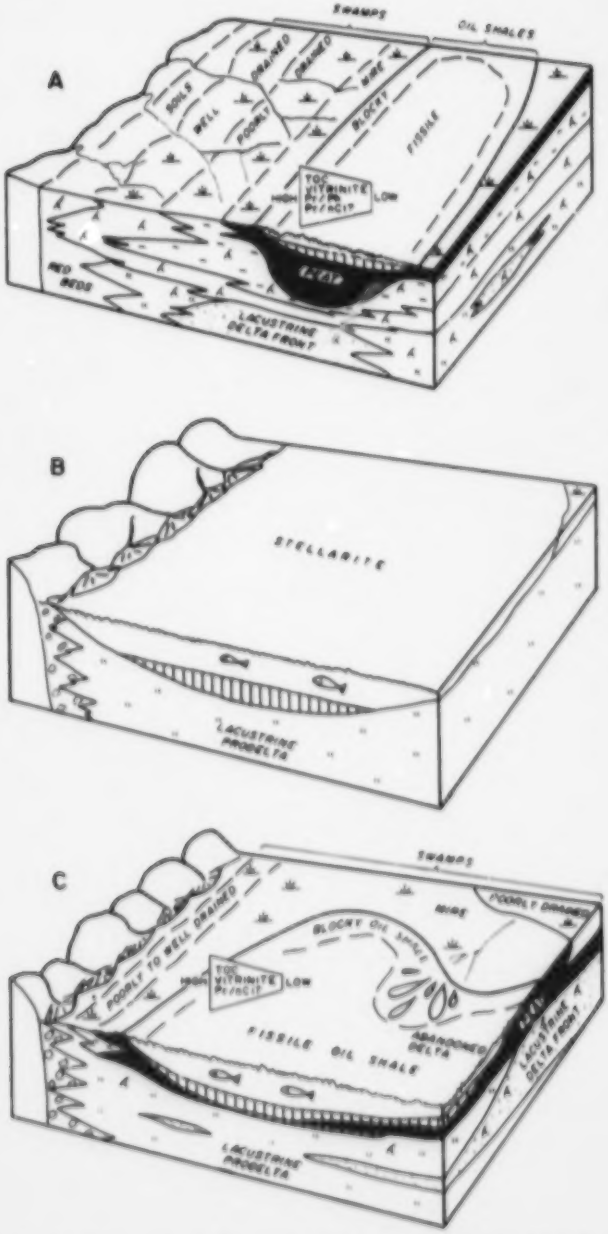

Fig. 21. Diagrammatic illustration of the lacustrine depositional environments of the Stellarton oil shales. (A) the depositional environment of blocky and fissile oil shale during deposition of the Westville and Albion Members; (B) the depositional environment of stellarite oil shale; (C) the depositional environment of blocky and fissile oil shale during deposition of the Coal Brook and Thorburn Members.

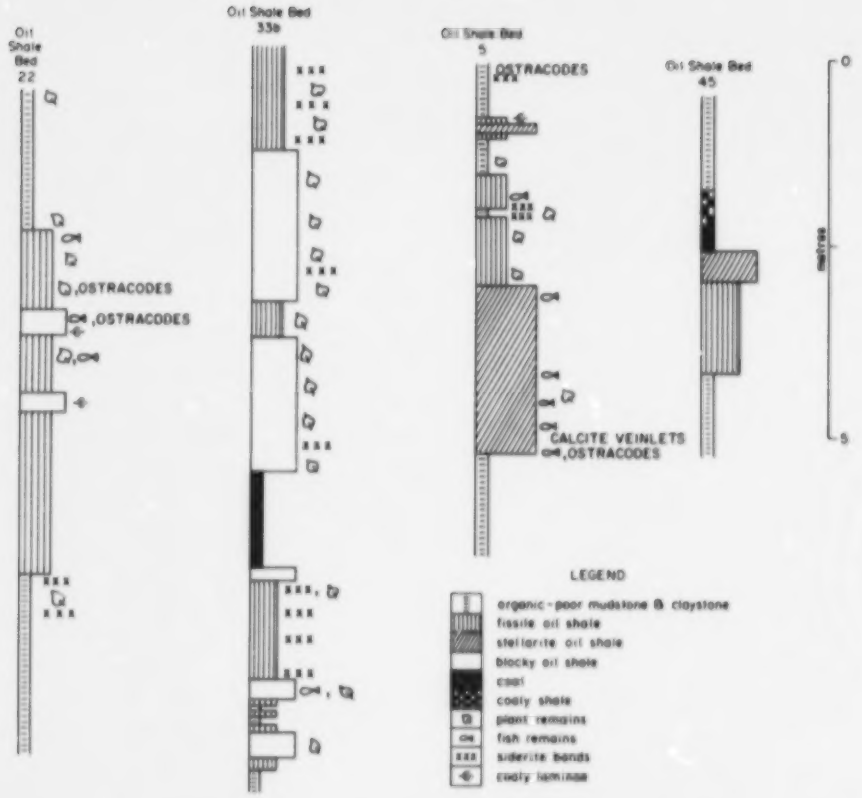

Fig. 22. Selected vertical sequences of Stellarton Formation lithotypes to illustrate the observed gradation between oil shale types and associated lithologies. From left to right: Oil shale bed 22, Shaw Brick Company Open Pit mine, New Glasgow; Oil shale bed 33b, McLeod coal seam and oil shale bed 34 in Suncor Inc. drillhole AP0371; Oil shale bed 5 in Nova Scotia Department of Mines and Energy drillhole P59A; and Oil shale bed 45 in Nova Scotia Department of Mines and Energy drillhole P23. See Fig. 13 for the location of the sections.

and 0.43 for blocky oil shale) also suggests a reducing environment of deposition (Hunt, 1979).

The closeness of the lake setting to the peat-forming environment was a major factor controlling the organic composition of the oil shales. Blocky oil shale, generally richer in organic carbon than fissile oil shale, was probably deposited nearer to shore than fissile oil shale (Fig. 21a). Evidence supporting this interpretation includes the close association of coal and blocky oil shale in the stratigraphic column (e.g. oil shales 42, 44, 46–50, 52 and 58: Fig. 14b), occasional discontinuous coaly laminae in blocky oil shale, a pet-

rographic composition that is locally rich in vitrinite, and Pr/Ph and Pr/nC_{17} ratios comparable to those of coals tested from the same sequence. Thus, a section comprising fissile oil shale overlain by blocky oil shale (e.g. as shown in Fig. 22) reflects a transition from offshore to nearshore areas of the lacustrine environment.

The only significant occurrence of stellarite oil shale within the Albion Member is oil shale bed 45 immediately below the Oil Coal Seam (Fig. 14b, 22). The stellarite oil shale was deposited in a relatively well-oxygenated lake with limited input of terrestrially-derived plant detritus (Fig. 21b). A high Pr/Ph ratio of 4.1 for stellarite oil shale indicates an oxidizing environment according to Hunt (1979). However, the preservation of abundant organic matter implies that the algal remains accumulated rapidly, with immediate burial on the lake floor. The marked depletion of terrestrially derived organic matter within stellarite oil shale could imply: (1) a lack of intraswamp drainage into the lake; (2) more favourable conditions (e.g. lake chemistry) existed for the preservation of telalginite rather than terrestrial organic matter; or (3) the lake covered much of the basin floor leaving no room for the development of swamps (Fig. 21b).

During deposition of the Coal Brook and Thorburn Members, basin subsidence rates were high and a relatively deep perennial lake formed over much of the basin (Fig. 21c). Although sediment supply rates may have been high, not enough sediment was transported into the basin to completely infill the lake. Instead, deltaic deposits prograded into the lake forming coarsening-upward mud to sand sequences in the nearshore areas while offshore rhythmically layered muds were deposited. During periods of low sediment supply, organic-rich muds (oil shales) accumulated on the lake bottom and mires occasionally developed on areas infilled by deltaic sediments. These mires were gradually drowned as continued basin subsidence caused lacustrine transgression. This explains why the coals of the Thorburn and Coal Brook members thicken toward basin margins and pinch out towards the basin center.

Oil shale development was the most extensive during the period when the perennial lake existed, particularly during Coal Brook time. All three oil shale lithologies were deposited within the perennial lake, although probably not contemporaneously. Fissile oil shale grades from organic-poor mudrock or laminated claystone to either blocky oil shale or stellarite oil shale (Fig. 22). However, instances where blocky oil shale and stellarite oil shale pass vertically or laterally into each other are unknown.

The fissile, stellarite and blocky oil shale of the Coal Brook and Thorburn Members probably accumulated under similar conditions to those of the Albion and Westville Members (Fig. 21b,c). The stellarite oil shale of the Thorburn Member (oil shale beds 4a, 4, 5, 6) shows graded accumulations of telalginite (Fig. 17c), a feature not seen in stellarite oil shale of the Albion

Member (possibly because the latter is bioturbated by roots?: Dawson, 1868). The graded nature of the telalginite accumulations are probably due to variable rates of suspended solids deposition and/or algal bloom activity.

DISCUSSION AND CONCLUSIONS

The composition and depositional setting of the oil shales of the Albert and Stellarton Formations have been outlined throughout the paper and are summarized by Table 11. The purpose of this section will be to compare these two deposits by discussing how oil shale composition may have been influenced by: (1) basin setting and size, (2) water budget, (3) the presence or absence of swamps and (4) climate.

There are significant differences in the size and the paleogeographic setting of the Moncton Subbasin and the Stellarton Basin. The much larger 3750 km^2 Moncton Subbasin was only one of many lake basins within the Maritimes Basin during deposition of the Albert Formation (Hamblin, 1989; Martel, 1990). In contrast, during Westphalian C–D, when the 120 km^2 Stellarton Basin was a small lake basin, the rest of the Maritimes Basin was largely a fluvially dominated alluvial plain (Gibling et al., in press). A location adjacent to a large sediment-rich alluvial plain favoured high rates of sediment supply to the Stellarton Basin. The Moncton Subbasin, however, had to compete with other lake basins within the Maritimes Basin for regionally-sourced sediment. Lake basins are very efficient sediment traps, therefore, sediment transport throughout the Maritimes Basin during deposition of the Albert oil shales may have been relatively inefficient. This coupled with the much larger size of the Moncton Subbasin Basin may explain why it was periodically starved of siliclastic sediment. The significant quantity of calcite and dolomite (ankerite) in Albert oil shales could therefore be attributed simply to the absence of clastic dilution. Conversely, the virtual absence of carbonates and predominance of clays within the Stellarton oil shales can be explained in part, by relatively high rates of sediment supply to the small lakes of the Stellarton Basin.

The contrast in inorganic composition (e.g. mineralogy) of the Albert and Stellarton oil shales implies that the lakes in which they were deposited had different water budgets and, consequently, different water chemistry. The oil shales of the Albert Formation contain abundant carbonate and locally analcite and minor halite. This suggests that the Albert lake(s) commonly had greater discharge (evaporation + outflow) than recharge (inflow + precipitation). This would favour the development of high ionic concentrations and thus chemical sedimentation (Allen and Collinson, 1986).

The clay-rich Stellarton oil shales pass laterally into coal (peat swamp deposits) or carbonaceous mudstone (poorly drained swamp deposits) near basin margins. This trend suggests that the lake shorelines were relatively sta-

TABLE II

Comparison of characteristics of the Albert Formation oil shales, New Brunswick, and the Stellarton Formation oil shales, Nova Scotia

	Albert oil shales	Stellarton oil shale
Age	Early Carboniferous	Late Carboniferous (Westphalian B–D)
Basin size, type	3750 km^2; fault-controlled; rapidly (?) subsiding, asymmetric	165 km^2; strike-slip (pull-apart), rapidly subsiding
Fm. thickness and duration	100–1500 m over ca. 15 m.y.	2600 over 4–5 m y.
Associated lithologies	Fluvial-deltaic and alluvial fan, local evaporites	Coal, lacustrine delta, minor alluvial fan sediments
Relative abundance and thickness	4% of Albert section; 1–20 m (4 m average) thick beds	60 oil shale beds; 18% of Stellarton section; 1–45 m (5.1 m average) thick beds
Oil shale lithology	laminated types (lamosite) and massive	fissile, blocky (in part canneloid) and stellarite (boghead shale)
Fossils	Palaeoniscoid and osteolepid crossoptygerian fish, ostracods	Ostracods, pelecypods, fish and plant remains
Mineralogy	Carbonate-rich: dolomite, calcite, illitic clays, quartz, feldspar, other clays, pyrite common, minor analcite	Silicate-rich: illitic clays, lesser quartz and feldspar, minor siderite, pyrite
TOC	up to 31.25 wt.%	up to 43.5 wt.%
Organic matter	Mainly lamalginite + liptodetrinite	Liptinitic groundmass + terrestrial organic matter, telalginite
Max. yield (l/t)	263	250
Depositional setting	Lacrustrine: probably stratified; aerobic + oxidizing surface, anaerobic + reducing depth : slightly saline + alkaline water : nearshore – high energy clastic input : offshore – quiescent, local density flow	Lacustrine: probably stratified; aerobic + oxidizing surface, anaerobic + reducing depth : commonly bordered by peat swamps : "seasonal" algal production; flooding or currents indicated

ble during oil shale deposition and, thus, water discharge was approximately equal to recharge. To achieve this balance, the Stellarton lakes were likely hydrologically open systems and, consequently, ionic concentrations probably remained low and chemical sediments were not deposited.

The presence or absence of swamps had an important influence on both the organic and inorganic composition of the Albert and Stellarton oil shales. The organic composition of the Albert oil shales (alginite-rich with predominately

Type I, I–IIA and IIA kerogens) implies a limited contribution of swamp derived organic matter to Albert lake(s). The apparent absence of peat forming swamps in the Moncton Subbasin, during Albert time may be attributed to: (1) the evolutionary state of Early Carboniferous plants and (2) harsh conditions brought on by restricted water supply.

The majority of the Stellarton oil shales contain a mixed maceral assemblage consisting primarily of vitrinite, inertinite and an amorphous liptinitic groundmass; the kerogens are predominantly Type IIB and III. The organic composition of the Stellarton oil shales clearly reflects the significant contribution of organic matter from the numerous paleoswamps of the Stellarton Basin. The chemistry of the swamp waters which entered the Stellarton lakes may also have been important in determining oil shale composition. Peat and associated waters typically have a pH of 4–4.5 (Reeves, 1968). Carbonates and analcite are generally believed to form more readily under alkaline conditions (Berry and Mason, 1959; Reeves, 1968; Mossman et al., 1987) such as interpreted for the Albert lake(s). Consequently acid drainage from the Stellarton swamps may have acted as a buffer to carbonate and analcite production in the Stellarton lakes.

Acidic lake waters may also have limited the quantity of algal-derived organic matter in the blocky and fissile oil shales of the Stellarton Formation. In contrast, alkaline and slightly saline waters, inferred for the Albert lake(s), are considered to be very conducive to algal growth (Hardie et al., 1978). The frequent generation of algal blooms in the Albert lake(s) may also have contributed to the biogenic precipitation of carbonates.

The influence of climate on the organic and inorganic composition of the Albert and Stellarton oil shales is uncertain. The Maritimes Basin was located just south of the equator during the Carboniferous (Scotese et al., 1979). Thus, depending on the altitude of the Moncton Subbasin and the Stellarton Basin, warm temperatures would have been likely. It is tempting to suggest that the abundance of carbonates and chlorides in the Albert Formation reflects a drier climate. However, depending on the influence of such features as basin setting and size on oil shale composition, the climate during Albert and Stellarton oil shale deposition may not have been that much different. In fact, oil shales in the Antigonish Basin (Fig. 1) which are equivalent in age to the Albert oil shales are clay-rich, similar to the Stellarton oil shales (Smith and Naylor, 1990). Taken in isolation, the occurrence of numerous coals within the Stellarton Formation could suggest a humid tropical climate. However, the major coal bearing sequences of the Stellarton Formation are in diachronous contact with red bed sequences which have often been cited as criteria for a drier climate.

In conclusion oil shale composition provides a sensitive record of the differences in the chemical, physical and biological conditions in the Albert and Stellarton lakes. Integration of oil shale compositional data with basin analy-

sis and regional paleogeographic information can provide important insights into controls on oil shale deposition.

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